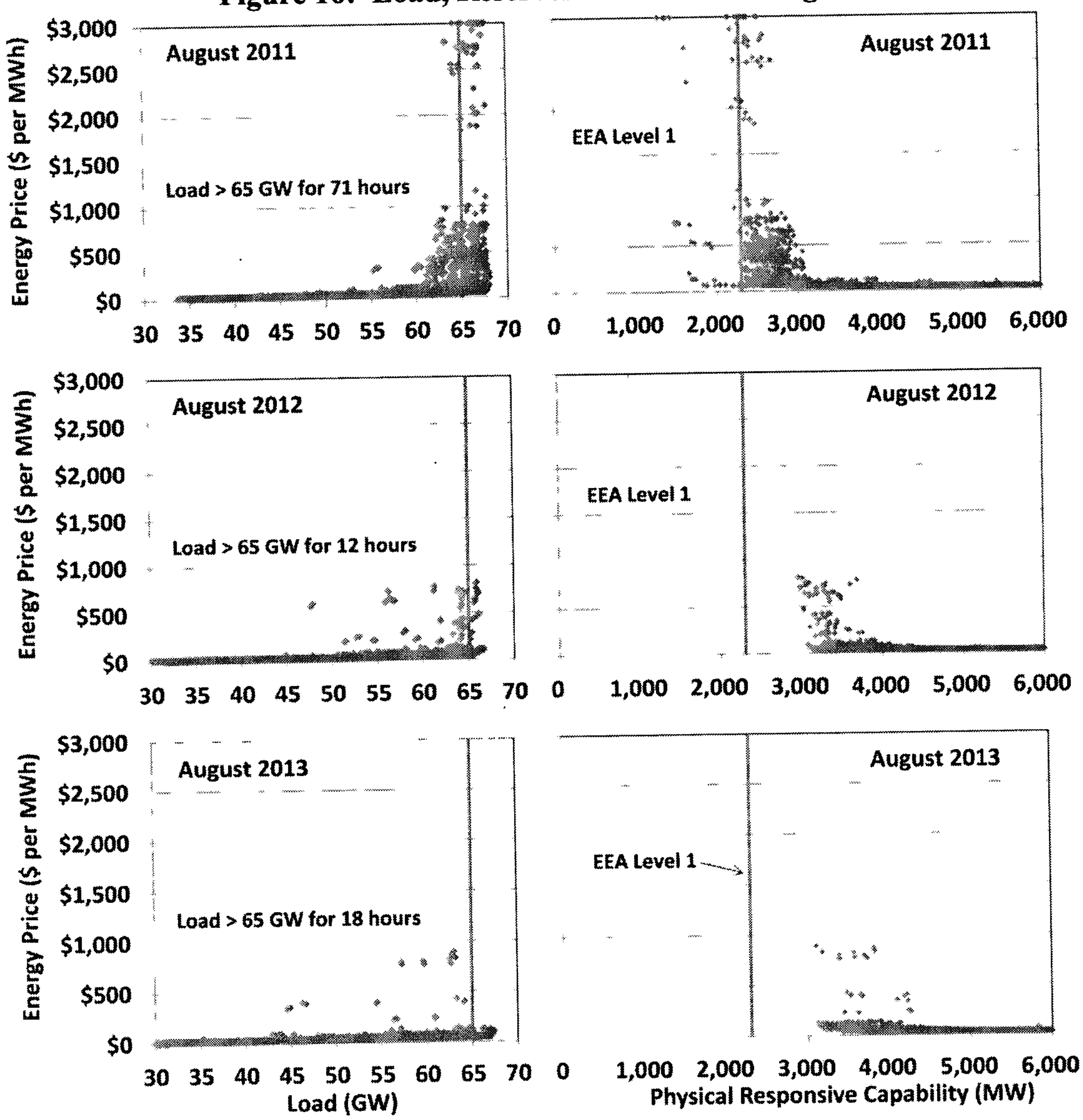
Further, there were no instances in 2013 of energy prices rising to the cap after the system-wide offer cap was increased to $5000 per MWh on June 1.

The next figure provides a detailed comparison of August's load, required reserve levels, and prices for 2011, 2012 and 2013. As expected, the weather in ERCOT was extremely hot and dry during August, but there were very few dispatch intervals when real-time energy prices reached the system-wide offer cap in 2012 and 2013 compared to the relatively high frequency it occurred in 2011. Although the weather may have been similar, there were significant differences in load and available operating reserve levels, resulting in much higher prices in August 2011.

**Figure 16: Load, Reserves and Prices in August**



Shown on the left side of Figure 16 is the relationship between real-time energy price and load level for each dispatch interval for the months of August 2011, 2012, and 2013. ERCOT loads were greater than 65 GW for 71 hours in 2011, whereas loads reached that level for 12 hours during August 2012 and 18 hours in August 2013. As previously discussed, a strong positive correlation between higher load and higher prices is expected in a well-functioning energy market. We observe such a relationship between higher prices and higher loads for all three months. However, that relationship appears to be weaker in the past two years with higher prices occurring at lower loads.

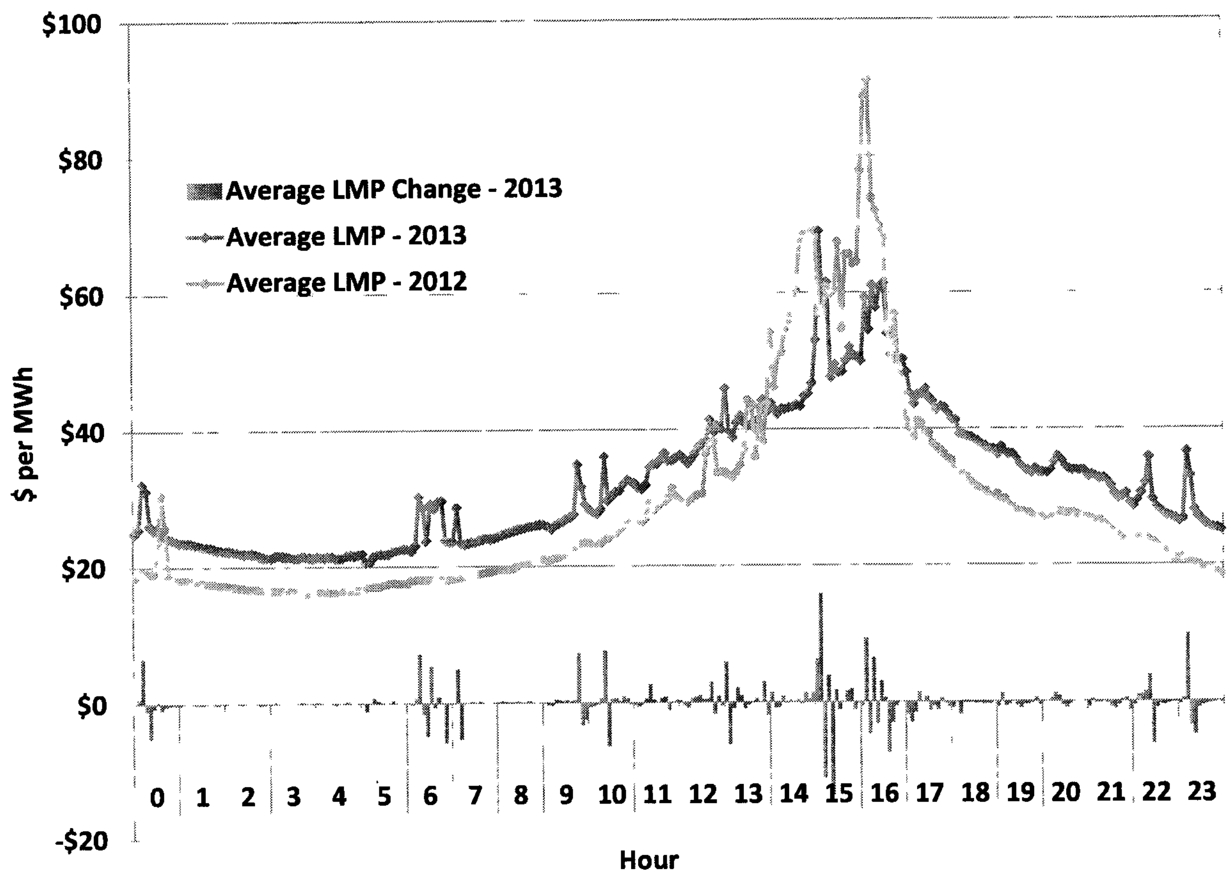
Although load levels are strong predictors of energy prices, an even more important predictor is the level of operating reserves. Simply put, operating reserves are the difference between the total capacity of operating resources and the current load level. As load level increases against a fixed quantity of operating capacity, the amount of operating reserves diminishes. The minimum required operating reserves prior to the declaration of Energy Emergency Alert ("EEA") Level 1 by ERCOT is 2,300 MW. As the available operating reserves approach the minimum required amount, energy prices should rise toward the system-wide offer cap to reflect the degradation in system reliability.

On the right side of Figure 16 are data showing the relationship between real-time energy prices and the quantity of available operating reserves for each dispatch interval during August of 2011, 2012, and 2013. This figure shows a strong correlation between diminishing operating reserves and rising prices. With the lower loads in August 2012 and 2013, available operating reserves were well above minimum levels for the entire month, and there were no occurrences where the energy price reached the system-wide offer cap. In contrast, there were numerous dispatch intervals in August 2011 when the minimum operating reserve level was approached or breached, with 17.4 hours where prices reached the system-wide offer cap. It should be noted that during August 2011 there were a number of dispatch intervals where operating reserves were below minimum requirements with prices well below the level that would be reflective of the reduced state of reliability. In Section IV, Load and Generation at page 98, we provide an example explaining why this can occur and offer a recommendation for improvement.

## E. Real-Time Price Volatility

Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability of supply to adjust can be restricted by physical limitations of the resources and the transmission network. Figure 17 below presents a view of the price volatility experienced in ERCOT's real-time energy market during the summer months of May through August. Average five-minute real-time energy prices are presented along with the magnitude of change in price for each five-minute interval. Average real-time energy prices from the same period in 2012 are also presented. Comparing average real-time energy prices for 2013 with those from 2012, the effects of higher natural gas prices on average prices during non-peak hours and the effects of fewer shortage intervals during peak hours are observed.

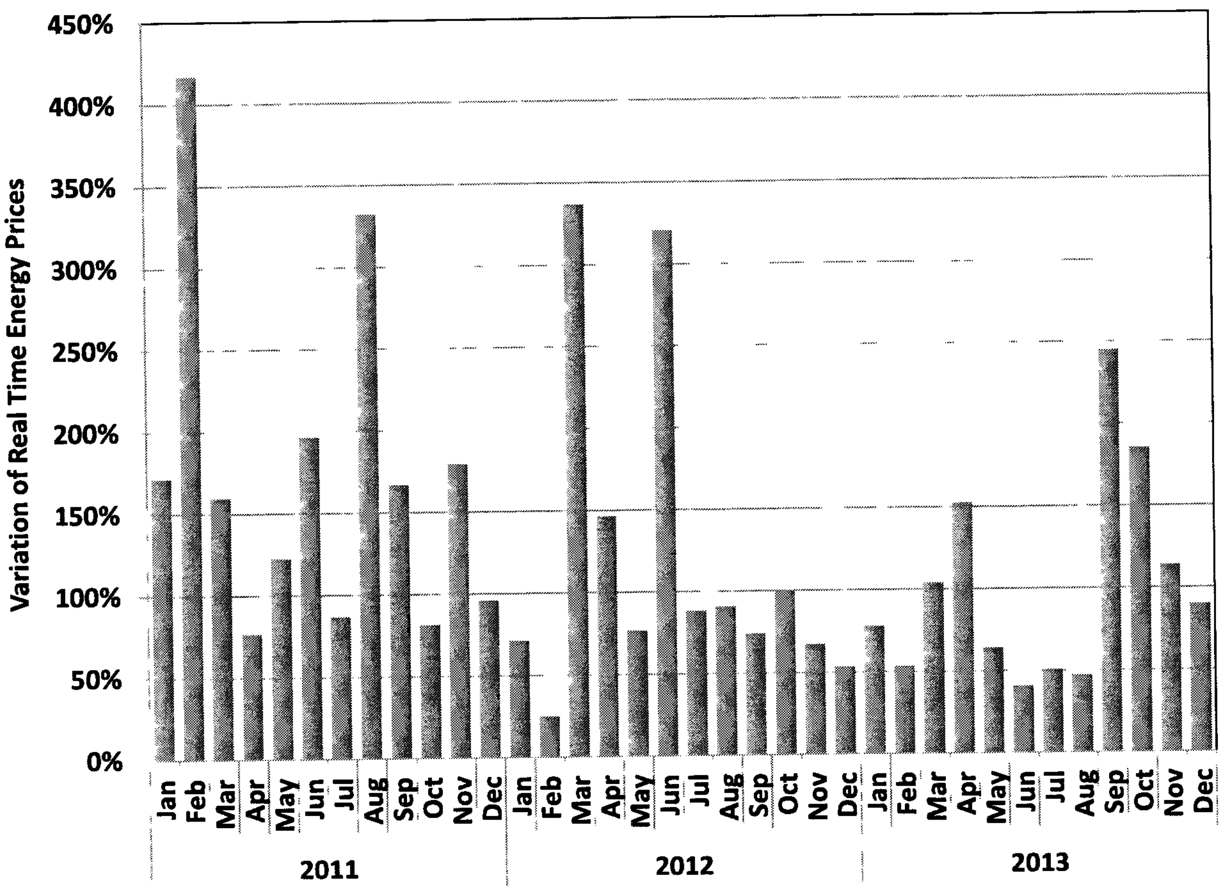
**Figure 17: Real-Time Energy Price Volatility (May – August)**




Outside of the hours from 15 to 18 (2:00 pm to 6:00 pm), short-term increases in average real-time energy prices are typically due to high prices resulting from generator ramp rate limitations occurring at times when significant amounts of generation is changing its online status. With higher natural gas prices in 2013, the price effects of these ramp limited periods were more noticeable in 2013. The average of the absolute value of changes in five-minute real-time energy prices, expressed as a percentage of average price was 3.4 percent in 2013, compared to 3.6 percent in 2012 and approximately 6.2 percent for the same period in 2011.

Expanding our view of price volatility, Figure 18 below presents the monthly variation in real-time prices. We observe that generally the months with highest price variability are those when real time prices rose to the system wide offer cap. Notable exceptions to this trend are observed in September and October of 2013.

**Figure 18: Monthly Price Variation**




The volatility of 15 minute settlement point prices for the four geographic load zones in 2013 was similar to that seen in 2012, as shown below in Table 1.

**Table 1: 15 Minute Price Changes as a Percentage of Annual Average Price**

| *Load Zone* | *2011* | *2012* | *2013* |
|---|---|---|---|
| Houston | 21.4% | 13.0% | 14.8% |
| South | 19.9 | 13.1 | 15.4 |
| North | 22.5 | 13.9 | 13.7 |
| West | 26.2 | 19.4 | 17.2 |

The table shows that the price volatility fell substantially from 2011 to 2012 and 2013. This was primarily due to the reduced duration of shortage pricing in 2012 and 2013. In contrast, 2011 exhibited the hottest summer temperatures in more than 100 years, leading to frequent shortages and associated higher price volatility. The table also shows that price volatility in the West zone has continued to be higher than in the other zones, which is expected given the very high penetration of variable output wind generation located in that area.

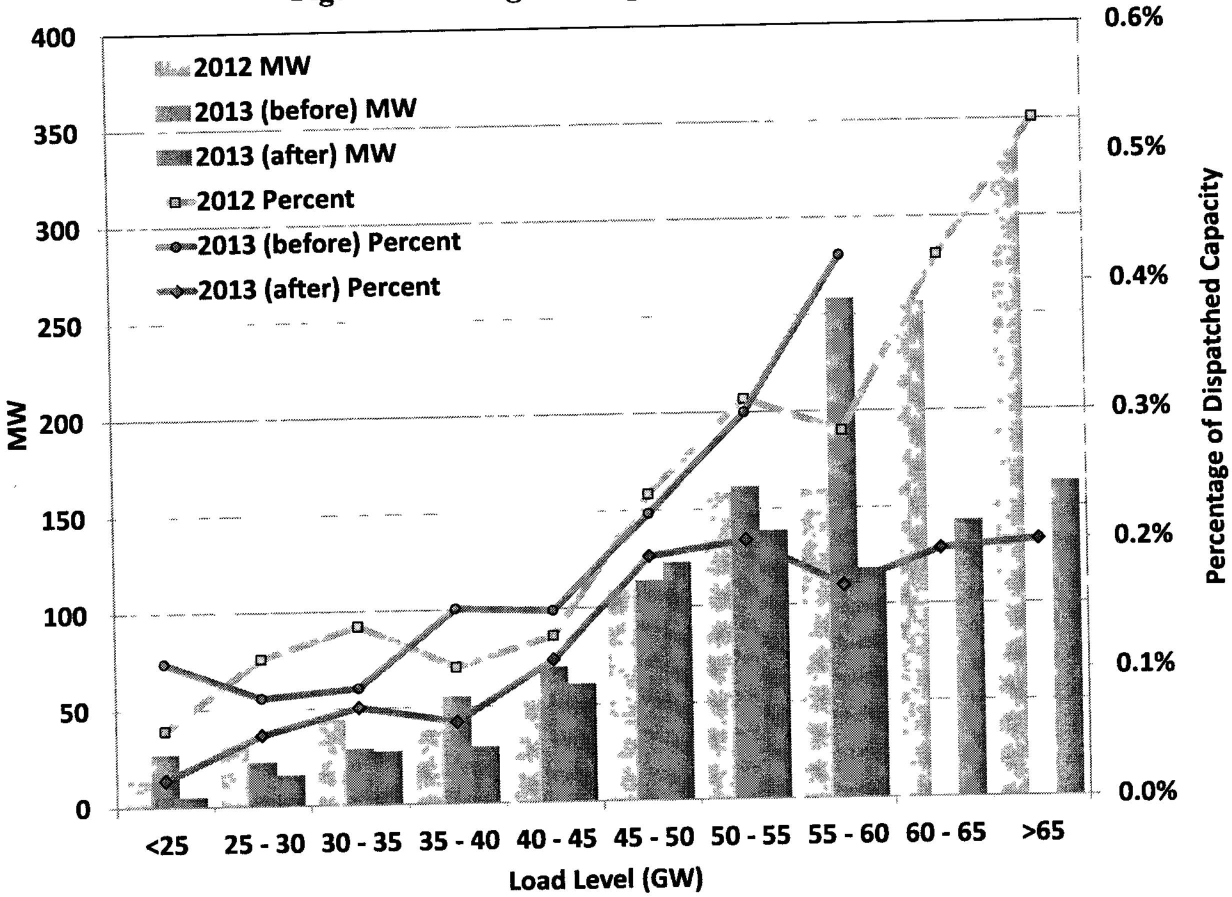
## F. Mitigation

ERCOT's dispatch software includes an automatic, two step price mitigation process. In the first step, the dispatch software calculates output levels (Base Points) and associated locational marginal prices using the participants' offer curves and only considering transmission constraints that have been deemed competitive. These "reference prices" at each generator location are compared with that generator's mitigated offer cap, and the higher of the two is used to formulate the offer curve to be used for that generator in the second step in the dispatch process. The resulting mitigated offer curve is used by the dispatch software to determine the final output levels for each generator, taking all transmission constraints into consideration. This approach is intended to limit the ability of a specific generator to raise prices in the event of a transmission constraint that requires their output to resolve. In this subsection we describe a change to the mitigation process that was implemented during 2013 and analyze the quantity of capacity affected by this mitigation process.

Although executing all the time, the automatic price mitigation aspect of the two step dispatch process only has an effect when a non-competitive transmission constraint is active. The mitigation process should limit the ability of a generator to affect price when their output is required to manage congestion. The process as initially implemented did not identify situations with sufficient competition between generators on the other (harmful) side of the constraint and would mitigate their offers as well. This unnecessary mitigation was addressed on June 12, 2013 with the implementation of changes described in NPRR520. With the introduction of an impact test to determine whether units are relieving or contributing to a transmission constraint, only the relieving units are now subject to mitigation. As shown below this had a noticeable effect on the amount of capacity subject to mitigation.

Our first analysis computes how much capacity, on average, is actually mitigated during each dispatch interval. The results, shown in Figure 19, are provided by load level.

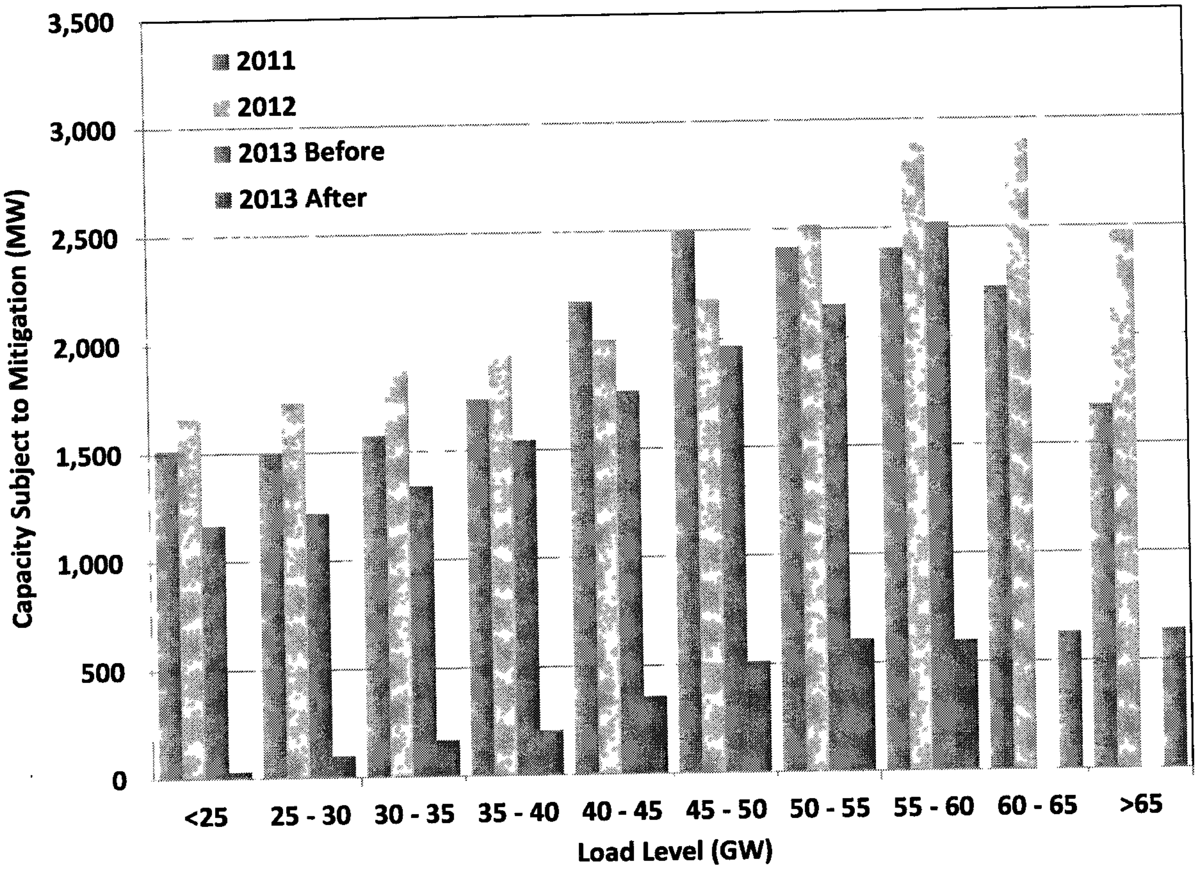
**Figure 19: Mitigated Capacity by Load Level**




The level of mitigation in 2013 before the rule change was very similar to that experienced in 2012. After the rule change there was a noticeable reduction in the percentage of dispatchable capacity being mitigated across all load levels. Further, during high load periods the amount of capacity being mitigated was reduced approximately in half.

In the previous figure only the amount of capacity that could be dispatched within one interval was counted as mitigated. In our next analysis we compute the total capacity subject to mitigation. These values are determined by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. We then take the difference between the total unit capacity and the capacity at the point the curves diverge. This calculation is performed for all units and aggregated by load level, as shown in Figure 20.

**Figure 20: Capacity Subject to Mitigation**




The effects of the rule change are very noticeable in Figure 20. Compared to 2012 where the amount of capacity subject to mitigation exceeded 1500 MW for all load levels, the amount of capacity subject to mitigation after the rule change in 2013 never reached 700 MW. Put another way, up to 7 percent of capacity required to serve load in 2012 was subject to mitigation. After the rule change this percentage decreased to 1 percent. An important note about this capacity measure is that it includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity was actually required to serve load.

## II. Review of Day-Ahead Market Outcomes

ERCOT's centralized day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Offers to sell can take the form of either a three-part supply offer, which allows sellers to reflect the unique financial and operational characteristics of a specific generation resource, or an energy only offer, which is location specific but is not associated with a generation resource. Bids to buy are also location specific. Ancillary services are also procured as part of the day-ahead market clearing. The third type of transaction included in the day-ahead market is bids to buy Point to Point ("PTP") Obligations, which allow parties to hedge the incremental cost of congestion between day-ahead and real-time operations.

With the exception of the acquisition of ancillary service capacity, the day-ahead market is a financial market. Although all bids and offers are evaluated in the context of their ability to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market clearing. These transactions are made for a variety of reasons, including satisfying the participant's own supply, managing risk by hedging the participant's exposure to the real-time market, or arbitraging with the real-time markets. For example, load serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all of these reasons, the performance of the day-ahead market is essential.

In this section we review energy pricing outcomes from the day-ahead market and compare their convergence with real-time energy prices. We will also review the volume of activity in the day-ahead market, including a discussion of PTP Obligations. We conclude this section with a review of the ancillary service markets.

### A. Day-Ahead Market Prices

One indicator of market performance is the extent to which forward and real-time spot prices converge over time. Forward prices will converge with real-time prices when two main conditions are in place: a) there are low barriers to shifting purchases and sales between the forward and real-time markets; and b) sufficient information is available to market participants to allow them to develop accurate expectations of future real-time prices. When these conditions are met, market participants can be expected to arbitrage predictable differences between forward prices and real-time spot prices by increasing net purchases in the lower-priced market and increasing net sales in the higher-priced market. These actions will tend to improve the convergence of forward and real-time prices.

In this subsection, we evaluate the price convergence between the day-ahead and real-time markets. This analysis reveals whether persistent and predictable differences exist between day-ahead and real-time prices, which participants should arbitrage over the long-term. To measure the short-term deviations between real-time and day-ahead prices, we also calculate the average of the absolute value of the difference between the day-ahead and real-time price on a daily basis.

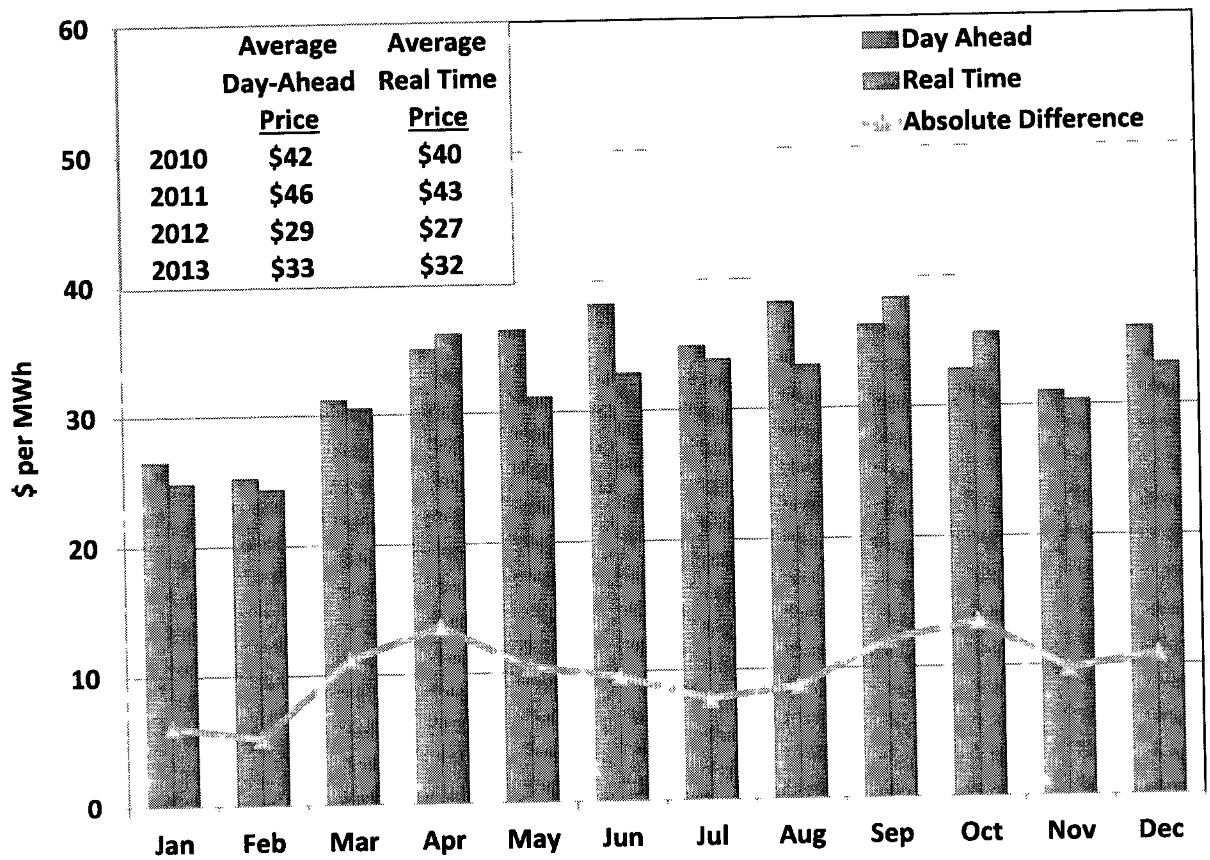
This measure captures the volatility of the daily price differences, which may be large even if the day-ahead and real-time energy prices are the same on average. For instance, if day-ahead prices are $70 per MWh on two consecutive days while real-time prices are $40 per MWh and $100 per MWh on the two days, the absolute price difference between the day-ahead market and the real-time market would be $30 per MWh on both days, while the difference in average prices would be $0 per MWh.

Figure 21 shows the price convergence between the day-ahead and real-time market, summarized by month. Day-ahead prices averaged $33 per MWh in 2013 compared to an average of $32 per MWh for real-time prices.[6] The average absolute difference between day-ahead and real-time prices was $9.86 per MWh in 2013; slightly lower than in 2012 when average of the absolute difference was $9.96 per MWh. This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead and higher for generators selling day-ahead. The higher risk for generators is associated with the potential of incurring a forced outage and as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest demand and highest prices.

6 These values are simple averages, rather than load-weighted averages presented in Figure 1and Figure 2.

Overall, the day-ahead premiums were very similar to the differences observed in 2012, but remain higher than observed in other organized electricity markets. Real-time energy prices in ERCOT are allowed to rise to levels that are much higher than what is allowed in other organized electricity markets, which increases risk and helps to explain the higher day-ahead premiums regularly observed in ERCOT. Although most months experienced a day-ahead premium (*e.g.*, $5 per MWh in May, June and August), it should not be expected over time that every month will always produce a day-ahead premium as the real-time risks that lead to the premiums will materialize unexpectedly on occasion, resulting in real-time prices that exceed day-ahead prices (*e.g.*, in April, September and October).

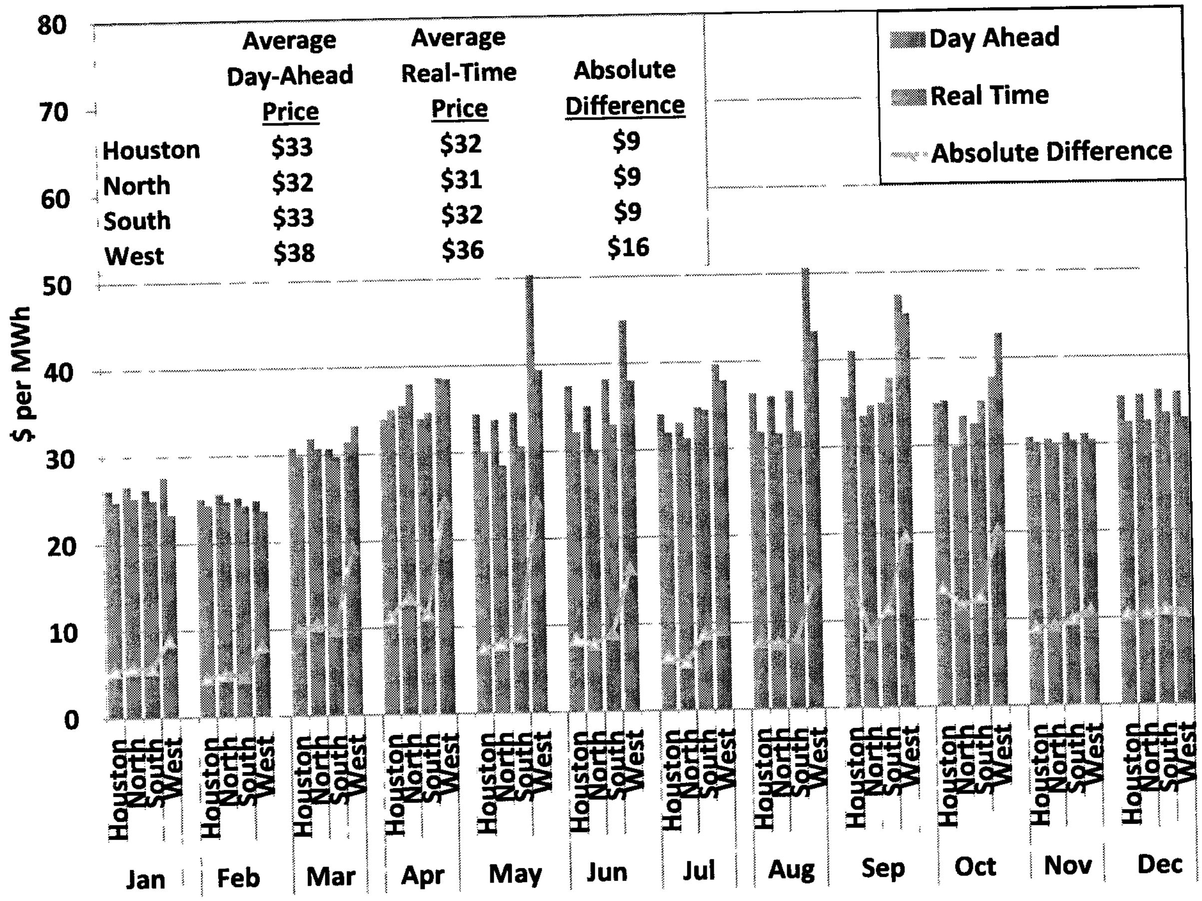
**Figure 21: Convergence between Forward and Real-Time Energy Prices**




| | Average Day-Ahead Price | Average Real Time Price |
|---|---|---|
| 2010 | $42 | $40 |
| 2011 | $46 | $43 |
| 2012 | $29 | $27 |
| 2013 | $33 | $32 |

In Figure 22 below, monthly day-ahead and real-time prices are shown for each of the geographic load zones. Of note is the difference in the West zone data compared to the other regions. The higher volatility in West zone pricing is likely associated with the uncertainty of forecasting wind generation output and the resulting price differences between day-ahead and real-time.

**Figure 22: Day-Ahead and Real-Time Prices by Zone**




## B. Day-Ahead Market Volumes

Our next analysis summarizes the volume of day-ahead market activity by month. In Figure 23 below, we find that the volume of day-ahead purchases provided through a combination of generator specific and virtual energy offers was approximately 50 percent of real-time load in 2013. This is an increase from 2012, when they totaled 45 percent. This increase was primarily due to a 42 percent increase in the volume of virtual energy offers. The volume of generator specific purchases increased approximately 2 percent in 2013 compared to 2012.

As discussed in more detail in the next subsection, Point to Point Obligations are financial instruments purchased in the day-ahead market. Although these instruments do not themselves involve the direct supply of energy, they do provide the ability to avoid the congestion costs associated with transferring the delivery of energy from one location to another. To provide a volume comparison we aggregate all of these "transfers", netting location specific injections against withdrawals. The volume of PTP Obligations in 2013 was almost 6 percent lower than in 2012.

By adding the aggregated transfer capacity associated with purchases of PTP Obligations, we find that total volumes transacted in the day-ahead market are greater than real-time load by an average of 12 percent. However, the volume in excess of real-time load decreased in 2013 compared to 2012, when on average the monthly volume of PTP Obligations was 22 percent greater than real-time load.

**Figure 23: Volume of Day-Ahead Market Activity by Month**

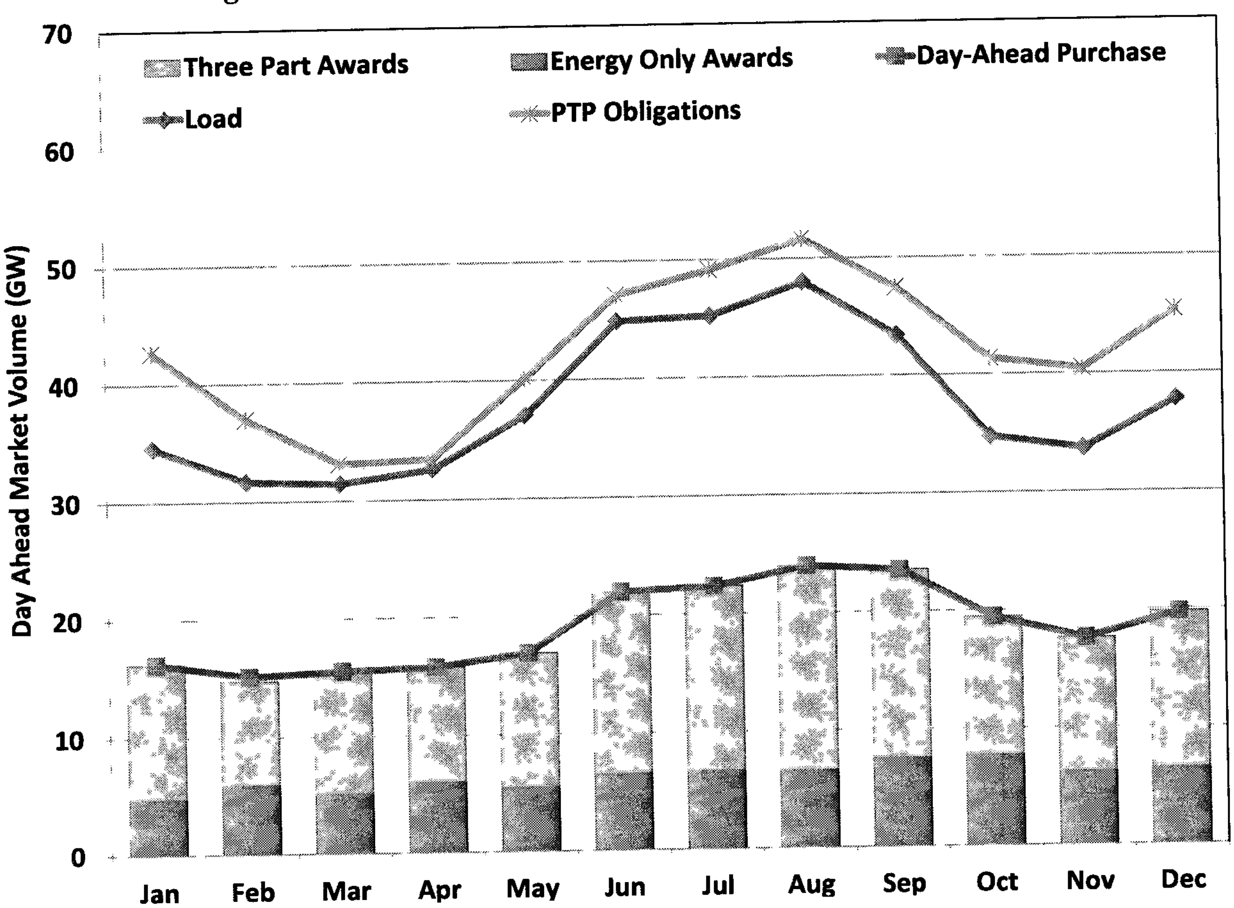
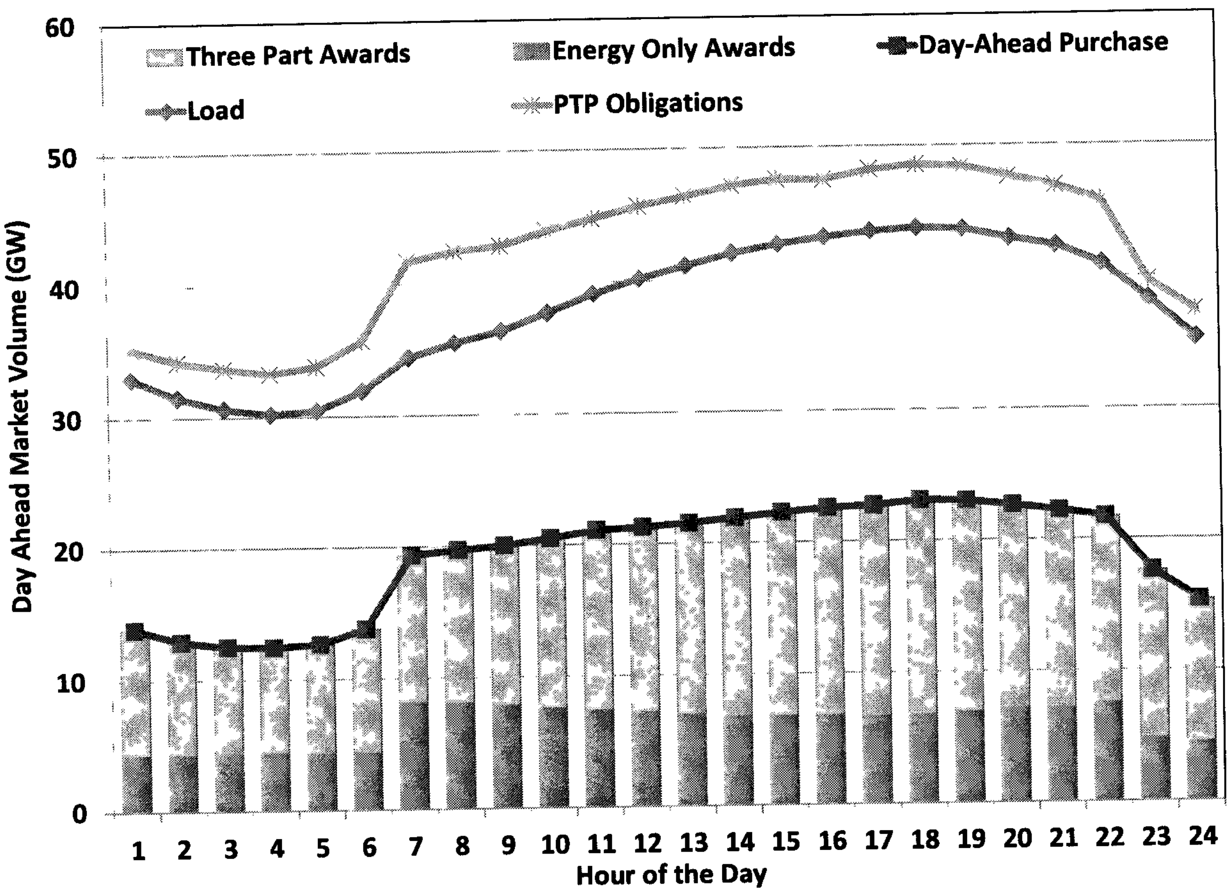



Figure 24 below, presents the same day-ahead market activity data summarized by hour of the day. In this figure the volume of day-ahead market transactions is disproportionate with load levels between the hours of 6 and 22. Since these times align with common bilateral transaction terms, it appears that market participants are using the day-ahead market to trade around those positions.

**Figure 24: Volume of Day-Ahead Market Activity by Hour**




## C. Point to Point Obligations

Purchases of Point to Point ("PTP") Obligations comprise a significant portion of day-ahead market activity. These instruments are similar to, and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section III, are acquired via monthly and annual auctions and allocations. CRRs accrue value to their owner based on locational price differences as determined by the day-ahead market. PTP Obligations are instruments that are purchased as part of the day-ahead market and accrue value to their owner based on real-time locational price differences. By acquiring a PTP Obligation using the proceeds due to them from their CRR holding, a market participant may be described as rolling their hedge to real-time.

In this subsection we provide additional details about the volume and profitability of these PTP Obligations.

**Figure 25: Point to Point Obligation Volume**

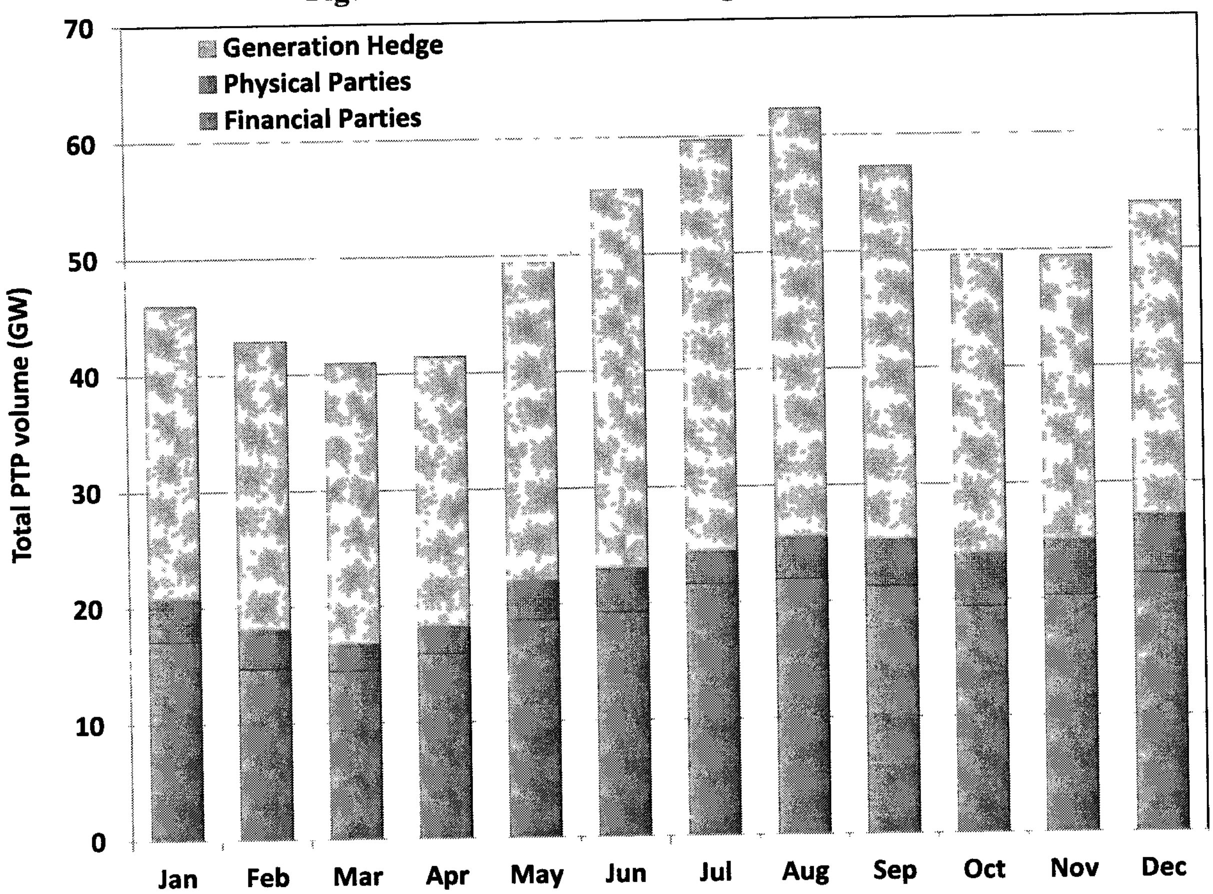
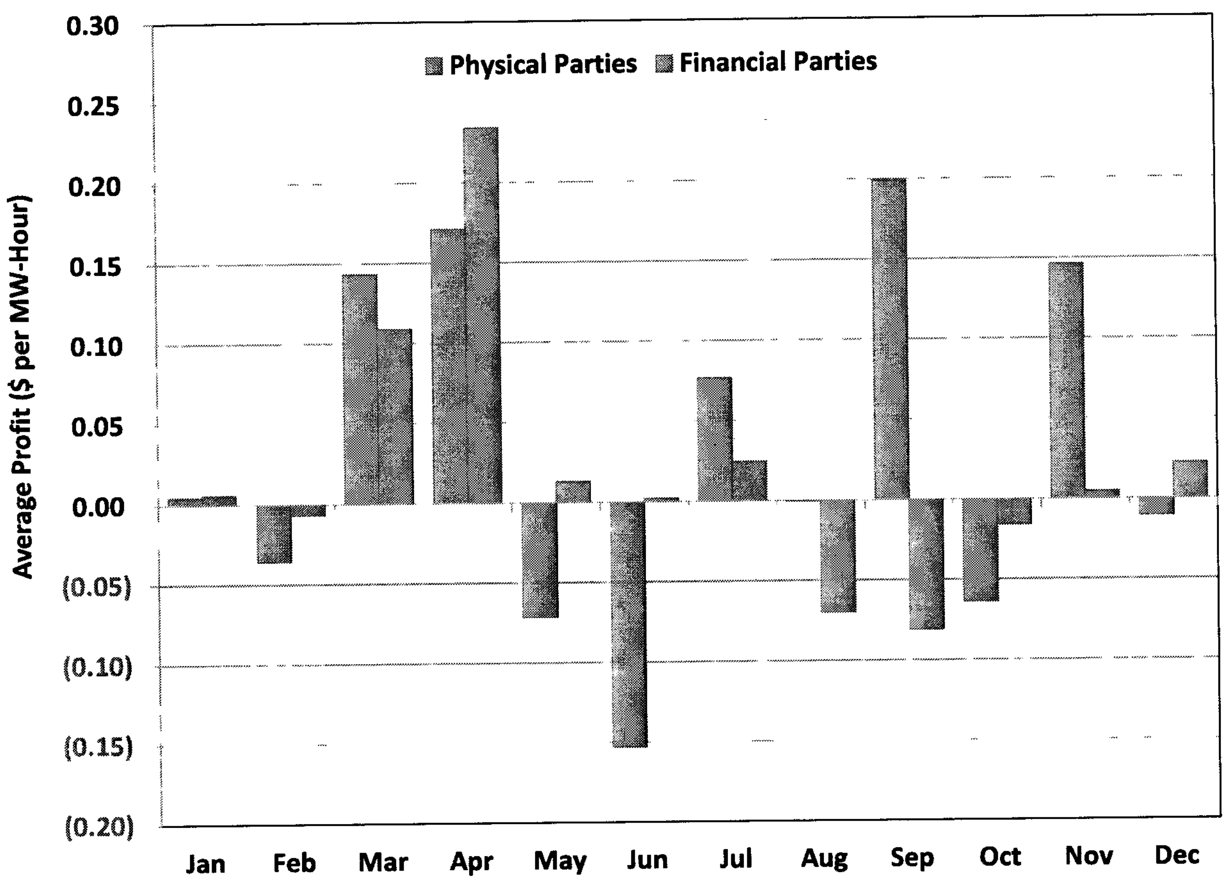



Figure 25 presents the total volume of PTP Obligation purchases divided into three categories. Compared to the previous two figures which showed net flows associated with PTP Obligations, in this figure we examine the total volume. For all PTP Obligations that source at a generator location, we attribute capacity up to the actual generator output as a generator hedge. From the figure above we see that this comprised most of the volume of PTP Obligations purchased. The remaining volumes of PTP Obligations are not directly linked to a physical position and are assumed to be purchased primarily to profit from anticipated price differences between two locations. We further separate this arbitrage activity by type of market participant. Physical parties are those that have actual real-time load or generation, whereas financial parties have neither.

To the extent the price difference between the source and sink of a PTP Obligation is greater in real-time than it was for the day-ahead price, the owner will have made a profit. Conversely, if the price difference does not materialize in real-time, the PTP Obligation may be considered unprofitable. We compare the profitability of PTP Obligation holdings by the two types of participants in Figure 26.

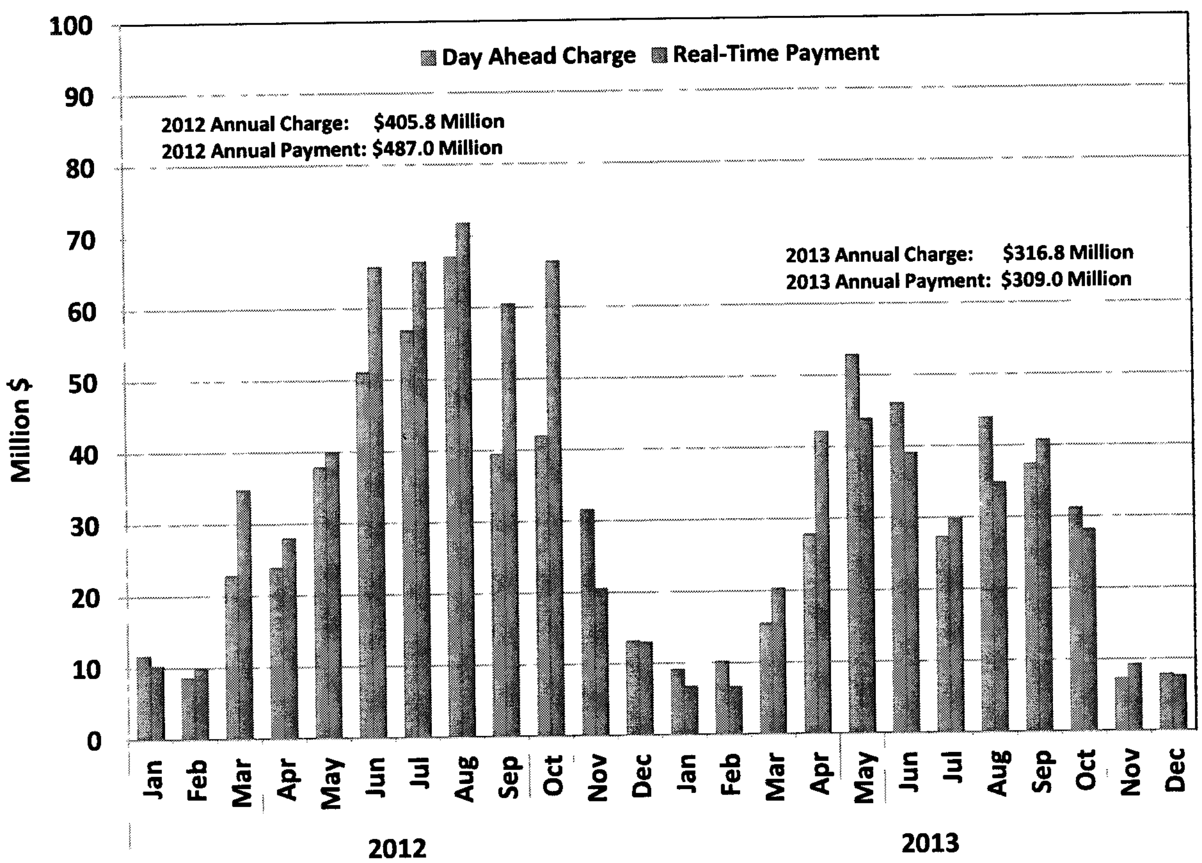
**Figure 26: Average Profitability of Point to Point Obligations**




In previous years this analysis has shown that there were two or three months where physical participants PTP Obligation holdings were unprofitable, and that the holdings of financial participants, in aggregate were profitable in all months. We may infer from the data shown in Figure 26 that PTP Obligation holdings, in aggregate, were much less profitable in 2013. These outcomes are more problematic for financial participants. With no real-time load or generation and therefore no other exposure to real-time prices, if a financial participant is not making a profit on their PTP Obligations there is no reason for them to buy any. It is their profit seeking action of buying PTP Obligations between points where congestion is expected that helps make the day-ahead market converge with real-time market outcomes. On the other hand, physical participants do have exposure to real-time prices. It is reasonable to expect that this type of participant is most interested in limiting that exposure by using PTP Obligations as a hedge.

To conclude our analysis of PTP Obligations, in Figure 27 we compare the total amount paid for these instruments day-ahead, with the total amount received by their holders in real-time.

**Figure 27: Point to Point Obligation Charges and Payments**

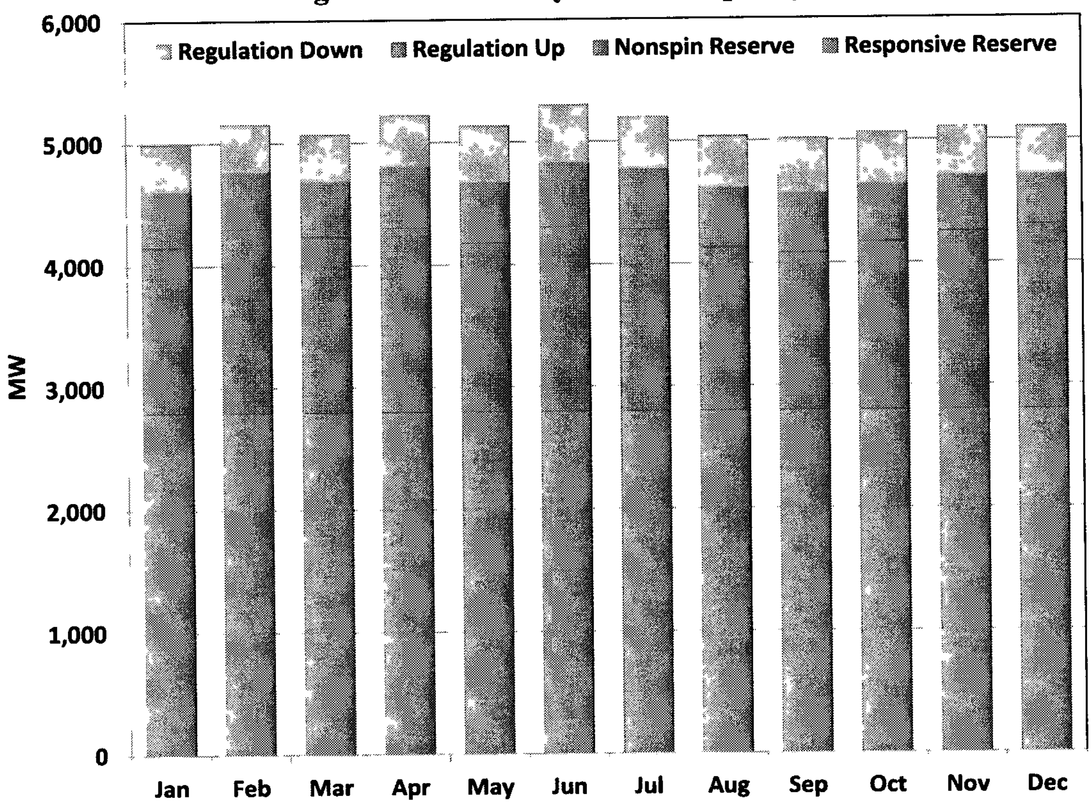



In prior years the aggregated total payments received by PTP Obligation owners was greater than the amount charged to the owners to acquire them. This occurs when real-time congestion is greater than what occurred in the day-ahead. This was not the case in 2013. Across the year, and in seven of twelve months, the acquisition charges were greater than the payments received, implying that expectations of congestion as evidenced by day-ahead purchases were greater than the actual congestion that occurred in real-time. The payments made to PTP Obligation owners come from real-time congestion rent. We assess the sufficiency of real-time congestion rent to cover both PTP Obligations and payments to owners of CRRs who elect to receive payment based on real-time prices in Section III, Transmission and Congestion at page 56.

## D. Ancillary Services Market

The primary ancillary services are up regulation, down regulation, responsive reserves, and non-spinning reserves. Market participants may self-schedule ancillary services or purchase their required ancillary services through the ERCOT markets. This subsection reviews the results of the ancillary services markets in 2013. We start with a display of the quantities of each ancillary service procured each month shown in Figure 28.

**Figure 28: Ancillary Service Capacity**

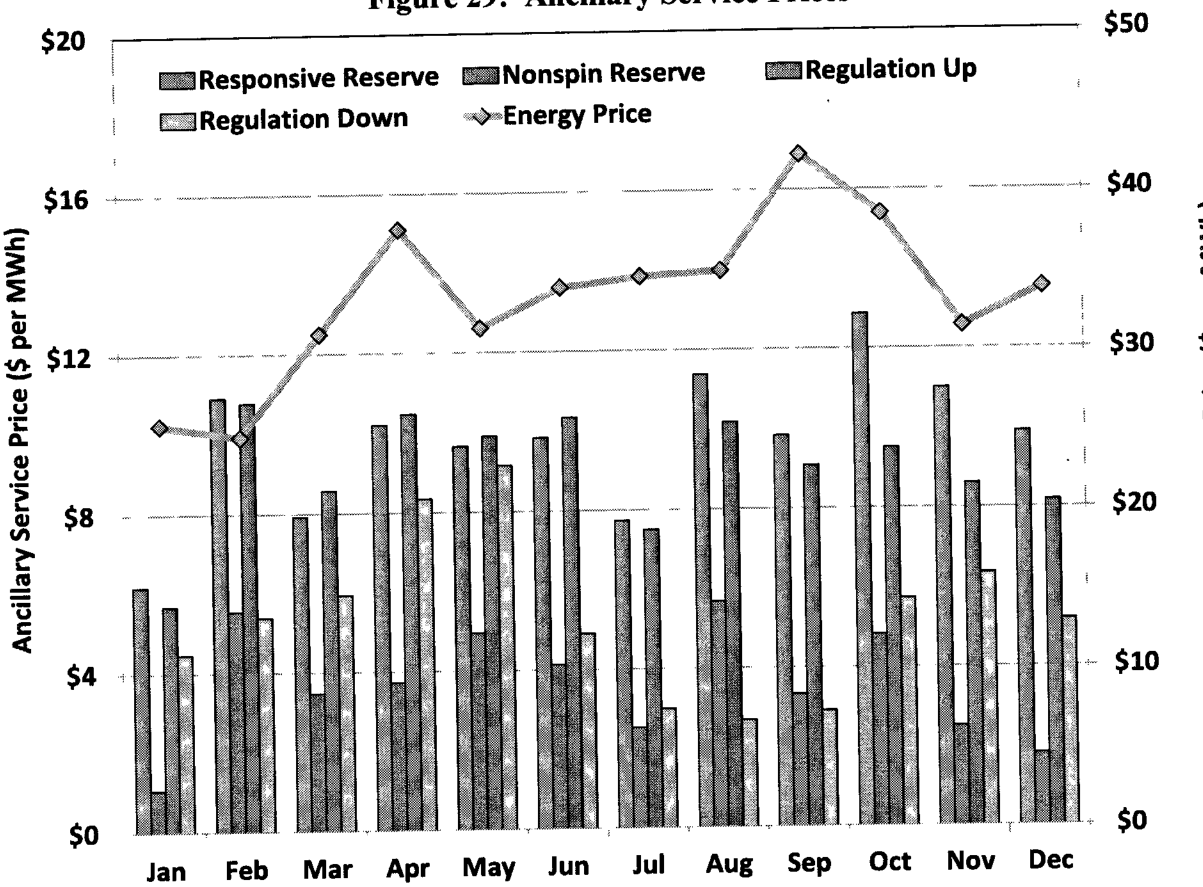



In general, the purpose of responsive and non-spinning reserves is to protect the system against unforeseen contingencies (*e.g.*, unplanned generator outages, load forecast error, wind forecast error), rather than for meeting normal load fluctuations. ERCOT procures responsive reserves to ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity. Non-spinning reserves are provided from slower responding generation capacity, and can be deployed alone, or to restore responsive reserve capacity. Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to fill the gap between energy deployments and actual system load.

The amount of responsive reserve was increased by 500 MW beginning in April 2012. This 500 MW increase was balanced with the same amount of decrease in the amount of non-spinning reserves procured. Although the minimum level of required responsive reserve remains at 2,300 MW, having the additional 500 MW of responsive reserve provides a higher quality – that is, faster responding capacity available to react to sudden changes in system conditions.

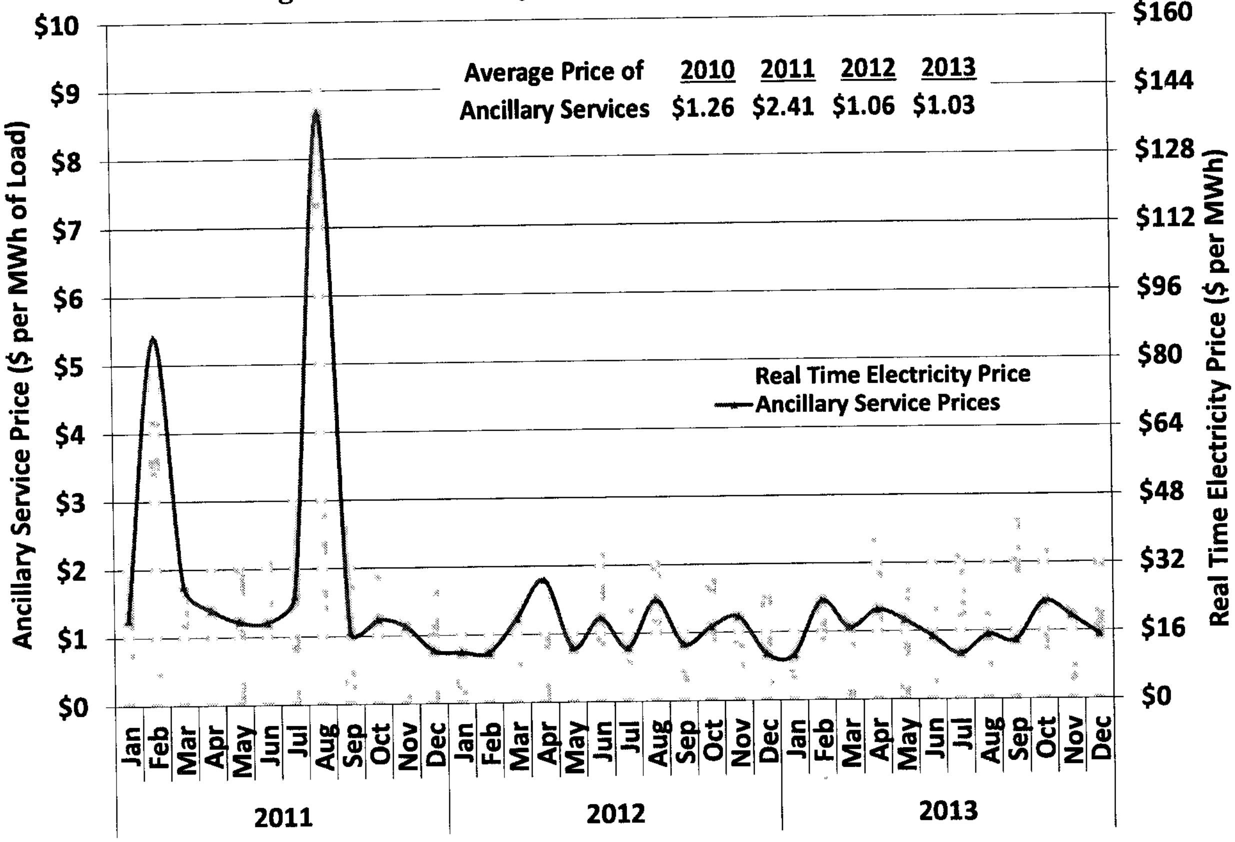
Under the nodal market, ancillary service offers are co-optimized as part of the day-ahead market clearing. This means that market participants no longer have to include their expectations of forgone energy sales in their ancillary services capacity offers. As a result of ancillary services clearing prices explicitly accounting for the value of energy, there is a much higher correlation between ancillary services prices and real-time energy prices.

**Figure 29: Ancillary Service Prices**




With average energy prices varying between $20 and $45 per MWh, we observe the prices of ancillary services remaining fairly stable throughout the year. In contrast to the previous data that showed the individual ancillary service capacity prices, Figure 30 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2011 through 2013. This figure shows that total ancillary service costs are generally correlated with real-time energy price movements, which are highly correlated with natural gas price movements as previously discussed. This occurs for two primary reasons. First, higher energy prices increase the opportunity costs of providing reserves and, therefore, can contribute to higher ancillary service prices. Second, shortages cause both ancillary service prices and energy prices to rise sharply so increases or decreases in the frequency of shortages will contribute to this observed correlation.

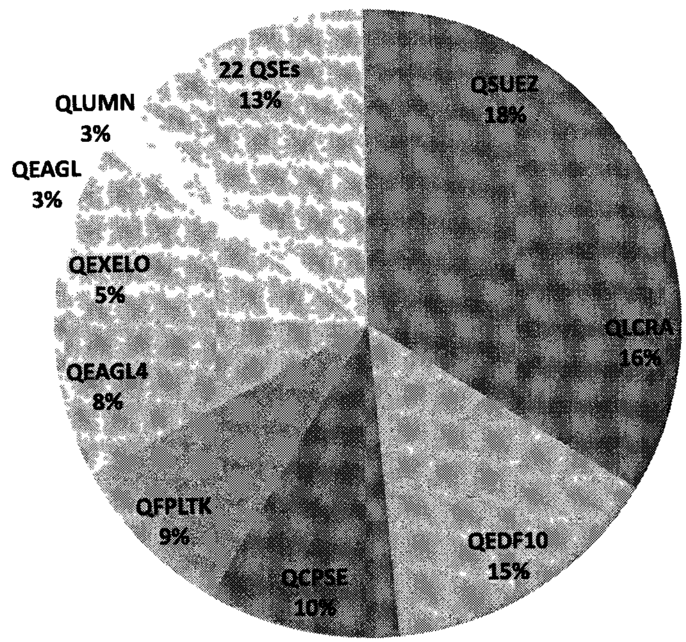
Figure 30: Ancillary Service Costs per MWh of Load




The average ancillary service cost per MWh of load decreased to $1.03 per MWh in 2013 compared to $1.06 per MWh in 2012, a decrease of 3 percent. Total ancillary service costs decreased from 3.7 percent of the load-weighted average energy price in 2012 to 3.0 percent in 2013.

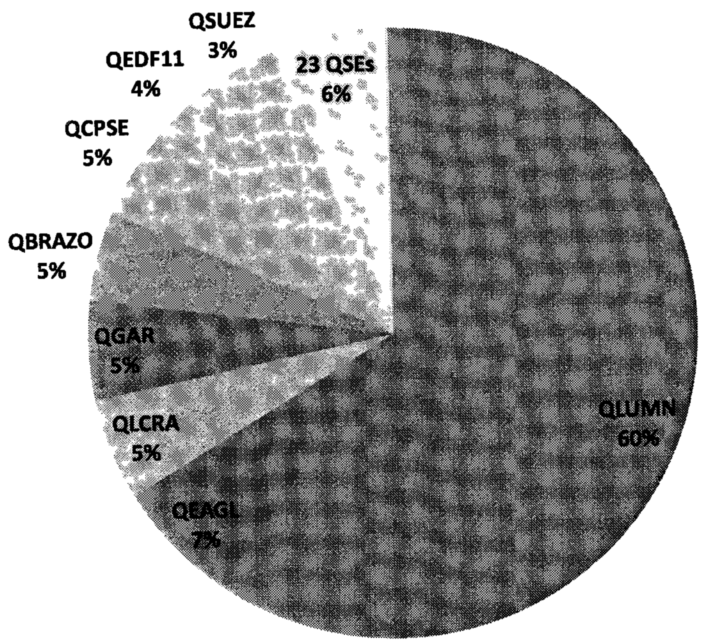
Responsive reserve service is the largest quantity and typically the highest priced ancillary service product. Figure 31 below shows the share of the 2013 annual responsive reserve requirements provided by each QSE. We observe that 31 different QSEs provided responsive reserve at some point during 2013, with multiple QSEs providing sizable shares.

**Figure 31: Responsive Reserve Providers**




In contrast, Figure 32 below shows that the provision of non-spinning reserves is highly concentrated, with a single QSE providing 60 percent of the total amount of non-spinning reserves procured last year. We are not raising concerns with the competitiveness of the provision of this service during 2013. However, the fact that one party is consistently providing the preponderance of this service should be considered in the ongoing efforts to redefine the definition and required quantities of ERCOT ancillary services. Further, it highlights the importance of modifying the ERCOT ancillary service market design to co-optimize energy and ancillary services. Jointly optimizing all products in each interval allows the market to substitute its procurements between units on an interval-by-interval basis to minimize costs and set efficient prices. Additionally, it would allow higher quality reserves (e.g., responsive reserves) to be substituted for lower quality reserves (e.g., non-spin reserves), reducing the reliance upon a single entity to provide this type of lower quality reserves.

**Figure 32: Non-Spin Reserve Providers**

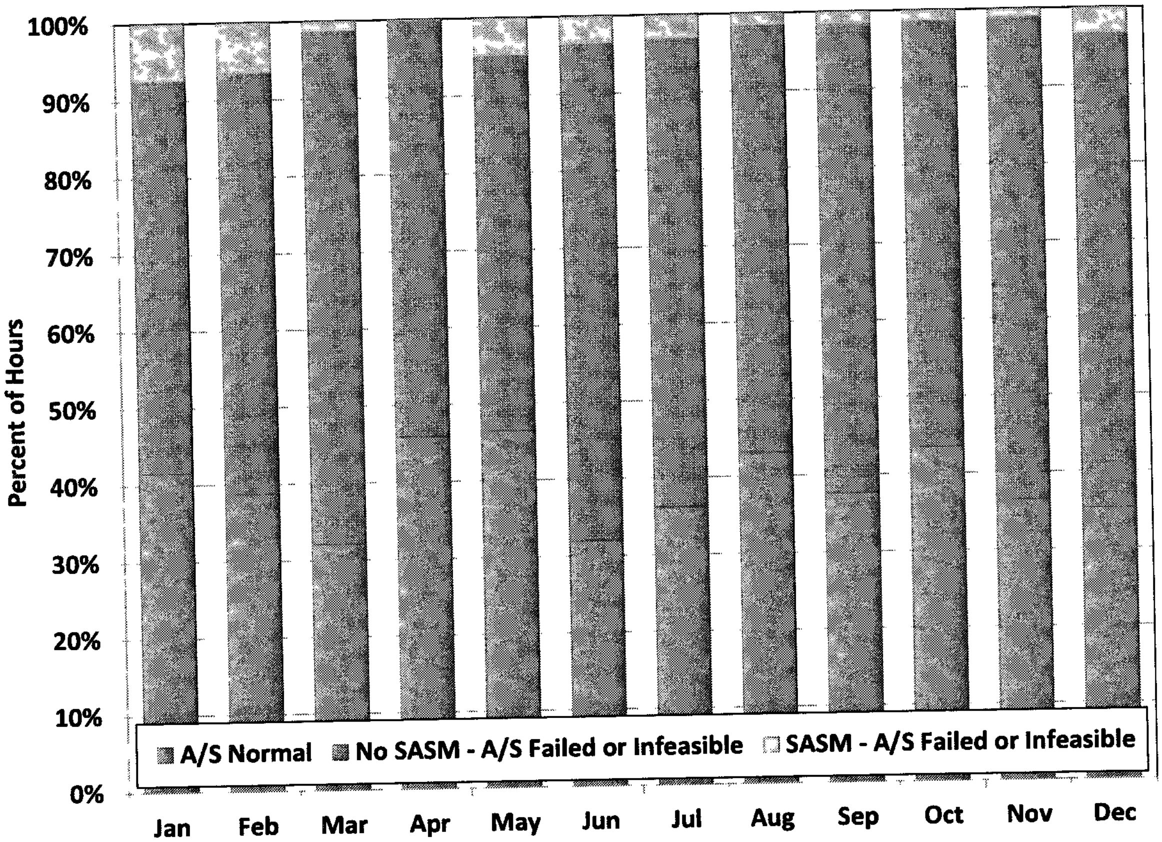



Ancillary Service capacity is procured as part of the day-ahead market clearing. Between the time it is procured and the time that it is required to be provided events can occur which make this capacity unavailable to the system. Transmission constraints can arise which make the capacity undeliverable. Outages or limitations at a generating unit can lead to failures to provide. When either of these situations occurs, ERCOT may open a supplemental ancillary services market ("SASM") to procure replacement capacity.[7]

Figure 33 below, presents a summary of the frequency with which ancillary service capacity was not able to be provided and the number of times that a SASM was opened in each month. The percent of time that capacity procured in the day-ahead actually provided the service in the hour it was procured for decreased to 39 percent in 2013, compared to 52 percent in 2012 and 43 percent in 2011. Even though in more than 60 percent of the hours there were deficiencies in ancillary service deliveries, SASMs were opened to procure replacement capacity in only 3 percent of the total hours, down from 7 percent of the hours in 2012 and 9 percent in 2011.

7 ERCOT may also open a SASM if they change their ancillary service plan. This did not occur during 2013.

**Figure 33: Frequency of SASM Clearing**




The primary reason that SASMs were infrequent was the dearth of ancillary service offers typically available throughout the operating day, limiting the opportunity to replace ancillary service deficiencies via a market mechanism. Without sufficient ancillary service offers available, ERCOT more frequently brings additional capacity online using reliability unit commitment procedures (RUC). Because co-optimization allows the real-time market far more flexibility to procure energy and ancillary services from online resources, it would likely substantially reduce ERCOT's need to use the RUC procedures to acquire ancillary services.

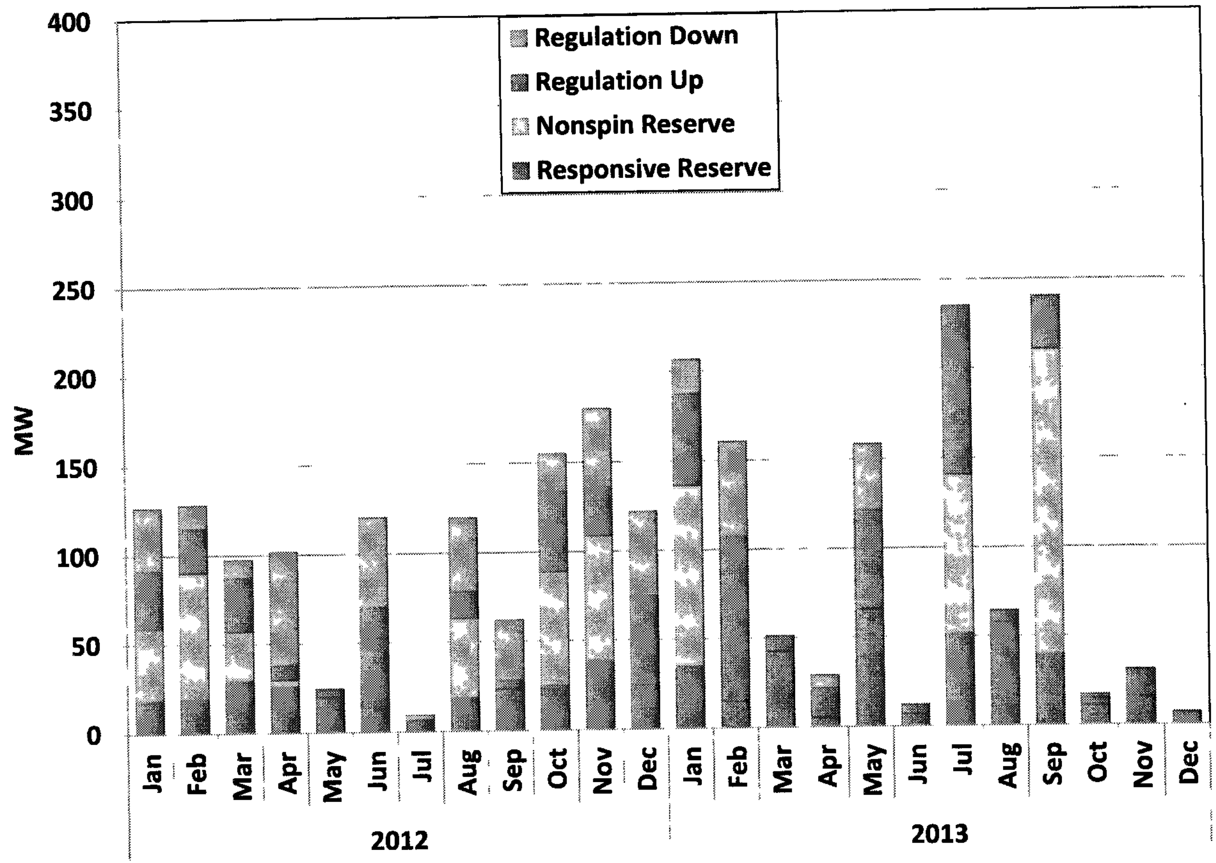
In Table 2 below, we provide an annual summary of the frequency and quantity of ancillary service deficiency, which is defined as either failure-to-provide or as undeliverable.

**Table 2: Ancillary Service Deficiency**

| *Service* | *Hours Deficient* | *Mean Deficiency (MW)* | *Median Deficiency (MW)* |
|---|---|---|---|
| **2013** | | | |
| Responsive Reserve | 3138 | 43 | 20 |
| Non-Spin Reserve | 610 | 50 | 38 |
| Up Regulation | 689 | 38 | 20 |
| Down Regulation | 575 | 39 | 15 |
| **2012** | | | |
| Responsive Reserve | 3756 | 34 | 15 |
| Non-Spin Reserve | 664 | 36 | 8 |
| Up Regulation | 750 | 41 | 25 |
| Down Regulation | 522 | 48 | 39 |
| **2011** | | | |
| Responsive Reserve | 4053 | 39 | 20 |
| Non-Spin Reserve | 1254 | 90 | 39 |
| Up Regulation | 1222 | 27 | 20 |
| Down Regulation | 1235 | 22 | 11 |

The number of hours with deficiency for most services decreased in 2013 when compared to 2012. The exception was down regulation, which had about a 10 percent increase in the number of hours of deficiency in 2013. Again during 2013, responsive reserve service was deficient most frequently. Well over 90 percent of the deficiency occurrences were caused by failure to provide by the resource rather than undeliverability related to a transmission constraint. The change in the average magnitude of deficiency was mixed, with responsive reserve and non-spin increasing and the regulation services decreasing slightly.

Figure 34: Ancillary Service Quantities Procured in SASM




Our final analysis in this section, shown in Figure 34, summarizes the average quantity of each service that was procured via SASM. As previously discussed, SASM was rarely used to replace deficiencies in ancillary services in 2013. When a SASM was used in 2013, the quantity of ancillary services procured was similar to that seen in 2012. Non-spinning reserves were procured less frequently, but in larger quantity. Regulation down was also procured less frequently and in smaller quantity.

# III. TRANSMISSION AND CONGESTION

One of the most important functions of any electricity market is to manage the flows of power over the transmission network by limiting additional power flows over transmission facilities when they reach their operating limits. The action taken to ensure operating limits are not violated is called congestion management. The effect of congestion management is to change generator(s) output level so as to reduce the amount of electricity flowing on the transmission line nearing its operating limit. Because the transmission system is operated such that it can withstand the unexpected outage of any element at any time, congestion management actions most often occur when a transmission element is expected to be overloaded if a particular unexpected outage (contingency) were to occur. Congestion leads to higher costs due to lower cost generation being reduced and higher priced generation increased. Different prices at different nodes are the result. The decision about which generator(s) will vary their output is based on the generator's energy offer curve and its relative shift factors to the contingency and constraint pair. This leads to a dispatch of the most efficient resources available to reliably serve demand.

This section of the report summarizes congestion activity in 2013, provides a review of the costs and frequency of transmission congestion in both the day-ahead and real-time markets, and concludes with a review of the activity in the congestion rights market.

## A. Summary of Congestion

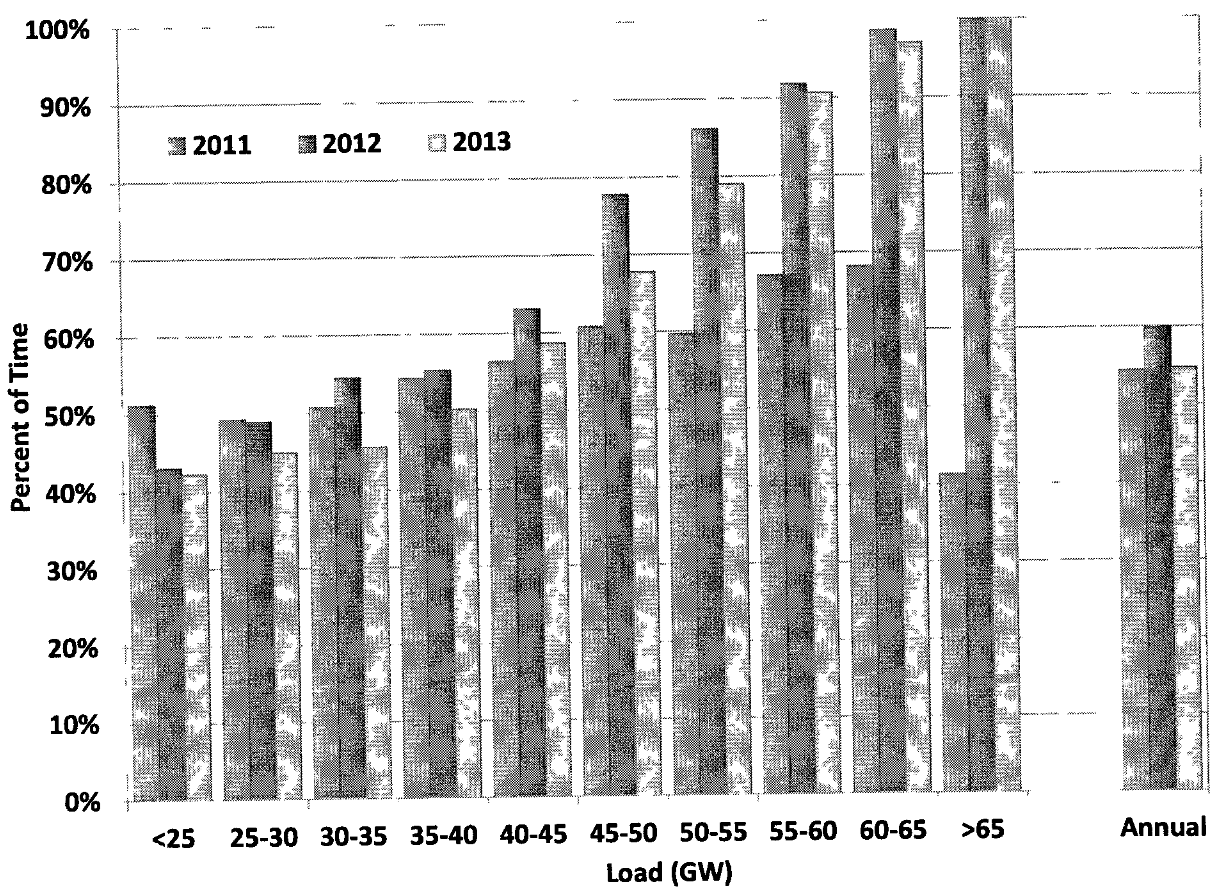
The total congestion revenue generated by the ERCOT real-time market in 2013 was $466 million, a decrease of 3 percent from 2012. This decrease is mostly attributed to transmission improvements in west Texas, specifically in the Odessa area as well as the completion of CREZ transmission projects. The largest contributors to the overall costs of congestion in 2013 were several localized transmission constraints in far west and south Texas.

Real-time transmission congestion during 2013 continued the trend seen since 2012 of localized higher load due to increased oil and natural gas production activity as the cause of most significant constraints. There was an increase in congestion within the South zone related to higher loads due to increased activity in the Eagle Ford shale during 2013 and outages within the South zone.

Given increases in local loads and the increase in fuel prices, it is noteworthy that transmission congestion decreased in 2013. This reduction was due in large part to transmission improvements that decreased the congestion levels in the West zone. Annual prices for loads located in the West zone were $11 per MWh higher than ERCOT average in 2012. In 2013, West zone prices were $5 per MWh higher. Further, due to the completion of the CREZ transmission lines longstanding limitations in the ability to export wind generation from the West zone were virtually eliminated by the end of 2013.

Figure 35 provides a comparison of the amount of time transmission constraints were active at various load levels in 2011 through 2013. Active transmission constraints are those for which generators are being dispatched to a less efficient output level in order to maintain transmission flows at reliable levels.

**Figure 35: Frequency of Active Constraints**




We observe that in 2013 the likelihood of having an active transmission constraint was slightly lower than in 2012, but still greater than 2011. We previously observed that during 2011, ERCOT operators did not always activate (or sometimes de-activated) transmission constraints during periods of higher system loads. This was due to a concern that by having a constraint active during periods of high demand the total capacity available to serve load may be limited. However, ERCOT's dispatch software contains parameters that allow it to automatically make the correct decision about when to violate transmission constraints when necessary to serve total system load. Therefore, ERCOT modified their practice in 2012 to retain active transmission constraints even during periods of high demand. Further, NERC standards support the continued management of transmission constraints under higher loads and potential scarcity conditions.

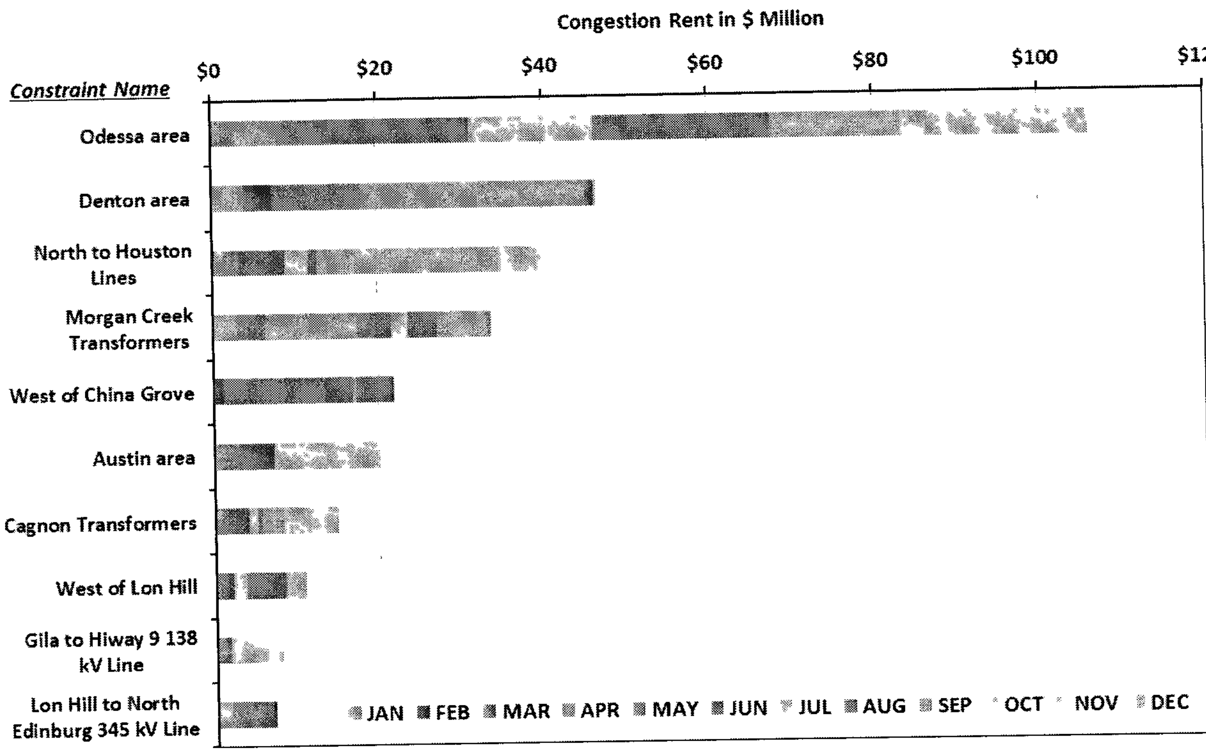
## B. Real-Time Constraints

We begin our review by examining the congested areas with the highest financial impact as measured by congestion rent. For this discussion we define a congested area by consolidating multiple real-time transmission constraints that we define as similar due to their geographical proximity and constraint direction. There were 388 unique constraints active at some point during 2013, a slight increase from the 360 constraints that were active in 2012. The median financial impact, as measured by congestion rent, was approximately $130,000 during 2013. This is a significant decrease from 2012, when the median impact was approximately $200,000.

Figure 36 below displays the ten most highly valued real-time congested areas as measured by congestion rent and indicates that the Odessa area was again the most congested location in 2013. The primary constraint in the area is attributed to the Odessa to Odessa North 138 kV line at $57 million, representing 54 percent of the total cost for the area. Following are the specific constraints comprising the Odessa area:

- Odessa to Odessa North 138 kV line
- Odessa EHV to Big Three Odessa 138 kV line
- Moss Switch to Amoco North Cowden 138 kV line
- Odessa North to Odessa Basin Switch 69 kV line
- Odessa North to North Cowden 69 kV line

## Figure 36: Top Ten Real-Time Congested Areas




The most significant constraint in 2012, the Odessa North 138/69 kV transformer, was no longer binding in 2013 because the transformer was replaced with one of a larger capacity in late 2012. Even with the elimination of the most significant constraint in 2012, the Odessa area continues to have the most real-time congestion in ERCOT, with more than twice the financial impact of the second congested area on the list.

The second congested area on the list is the Denton area, which contains the following constraints:

- Jim Christal – North Denton 138 kV line
- Fort Worth to Teasley 138 kV line
- Teasley – Pockrusc 138 kV line

The majority of the congestion in this area was due to outages in the area to accommodate transmission ugprades to support load growth in the Denton area.

A number of lines in the North to Houston corridor comprised the third most congested area in 2013:

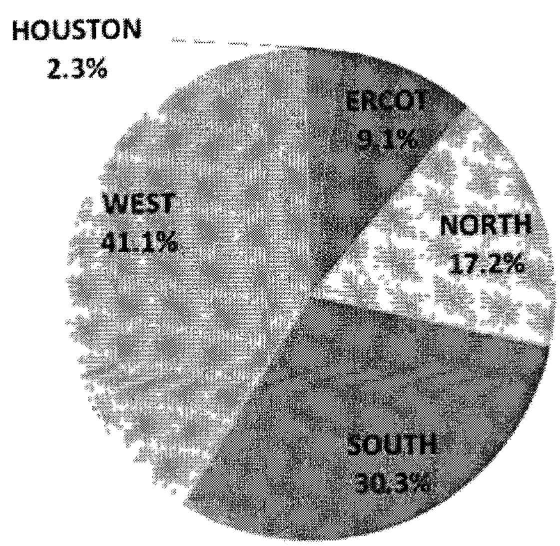
- Singleton to Zenith 345 kV line
- Singleton to Tomball 345 kV line
- Twin Oak – Jack Creek 345 kV line
- Jewett to Singleton 345 kV line
- Roans Prairie to Kuykendahl 345 kV line

Projects to decrease the impact of North to Houston congestion were being reviewed through the ERCOT Regional Planning process starting in July 2013.

Congestion related to the Morgan Creek transformer and in the area west of China Grove further highlights the impact load growth in the far west area of ERCOT. The Austin area and Cagnon transformer constraints were primarily due to nearby outages. The last three congested areas are smaller south zone constraints which contributed to making South zone congestion more prominent in 2013. Two of these three constraints are near Corpus Christi and the Eagle Ford shale, which has seen much higher loads due to oil and natural gas development. The third constraint, Lon Hill to North Edinburg 345 kV line, is related to longtime Valley Import limitations.

Figure 37 displays the percentage of real-time congestion costs attributed to each geographic zone. Those costs associated with constraints that cross zonal boundaries, i.e. North to Houston, are shown in the ERCOT category. The amount of real-time congestion associated with facilities located in the West zone was more than 40 percent of the total congestion costs in 2013. This is a decrease from 2012 when more than 55 percent of real-time congestion costs were from the West zone. As the percentage of congestion attributed to the West zone decreased, the share of congestion attributed to the south zone increased from less than 20 percent in 2012 to 30 percent in 2013.

**Figure 37: Real-Time Congestion Costs**



### *Irresolvable Constraints*

When a constraint becomes irresolvable, ERCOT's dispatch software can find no combination of generators to dispatch in a manner such that the flows on the transmission line(s) of concern are below where needed to operate reliably. In these situations, offers from generators are not setting locational prices. Prices are set based on predefined rules, which since there are no supply options for clearing, should reflect the value of reduced reliability for demand. To address the situation more generally, a regional peaker net margin mechanism was introduced such that once local price increases accumulate to a predefined threshold due to an irresolvable constraint; the shadow price of that constraint would drop.

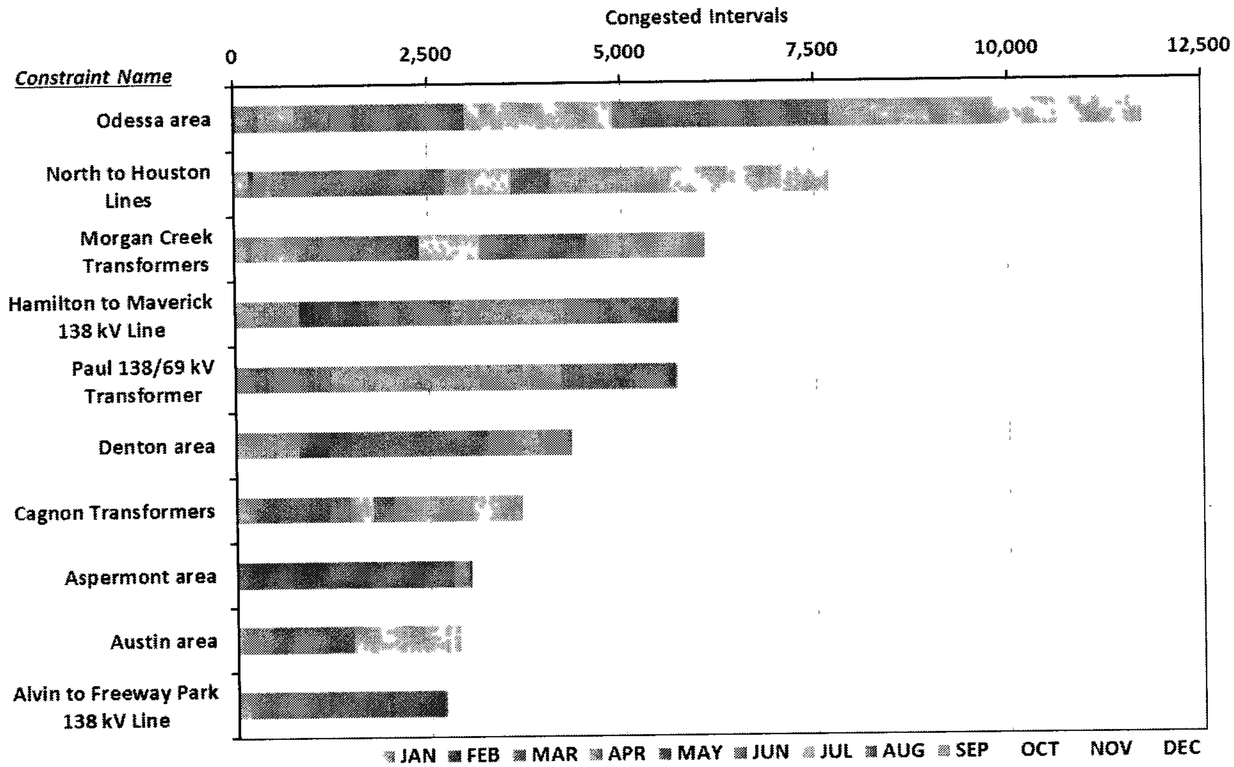
As shown below in Table 3, ten constraints, each comprised of a contingency and overloaded element, were deemed irresolvable in 2013 and as such, had a maximum shadow price cap imposed according to the Irresolvable Constraint Methodology. Three constraints are within the top ten real-time congested areas. Odessa North 138/69 kV transformer, China Grove to Bluff Creek 138 kV line, and Morgan Creek #1 345/138 kV Autotransformer were designated as irresolvable in 2013. The Wink TNP to Wink Sub 69 kV line qualified as irresolvable for the first time in May 2013. Four constraints from 2012 were deemed resolvable during the ERCOT analysis annual review and were removed from the list.

**Table 3: Irresolvable Constraints**

| Loss of: | Overloads: | Maximum Shadow Price | Effective Date |
|---|---|---|---|
| Base case | Valley Import | $2,000.00 | Jan 1, 2012 |
| Graham to Long Creek 345 kV line | Bomarton to Seymour 69 kV line | $2,000.00 | Jan 1, 2012 |
| Denton to Argyle / West Denton 138 kV lines | Jim Crystal to West Denton 69 kV line | $2,000.00 | Jan 1, 2012 |
| Odessa North to Holt 69 kV line | Odessa Basin to Odessa North 69 kV line | $2,800.00 | Jan 1, 2012 |
| Odessa to Morgan Creek / Quail 345 kV lines | China Grove to Bluff Creek 138 kV line | $2,000.00 | May 3, 2012 |
| Holt to Moss 138 kV line | Odessa North 138/69 kV transformer | $2000.00 | Aug 6, 2012 |
| Sun Switch to Morgan Creek 138 kV line | China Grove to Bluff Creek 138 kV line | $2,000.00 | Oct 11, 2012 |
| Morgan Creek #4 345 kV/138 kV Autotransformer | Morgan Creek #1 345 kV/138 kV Autotransformer | $2,000.00 | Nov 2, 2012 |
| Odessa Basin to Odessa North 69 kV line | Holt to Ector Shell Tap 69 kV line | $2,320.68 | Jan 1, 2013 |
| Wink TNP 138 kV/69 kV Autotransformer | Wink TNP – Wink Sub 69 kV line | $2,000.00 | May 20, 2013 |

Figure 38 presents a slightly different set of real-time congested areas. These are the most frequently occurring.

**Figure 38: Most Frequent Real-Time Congested Areas**

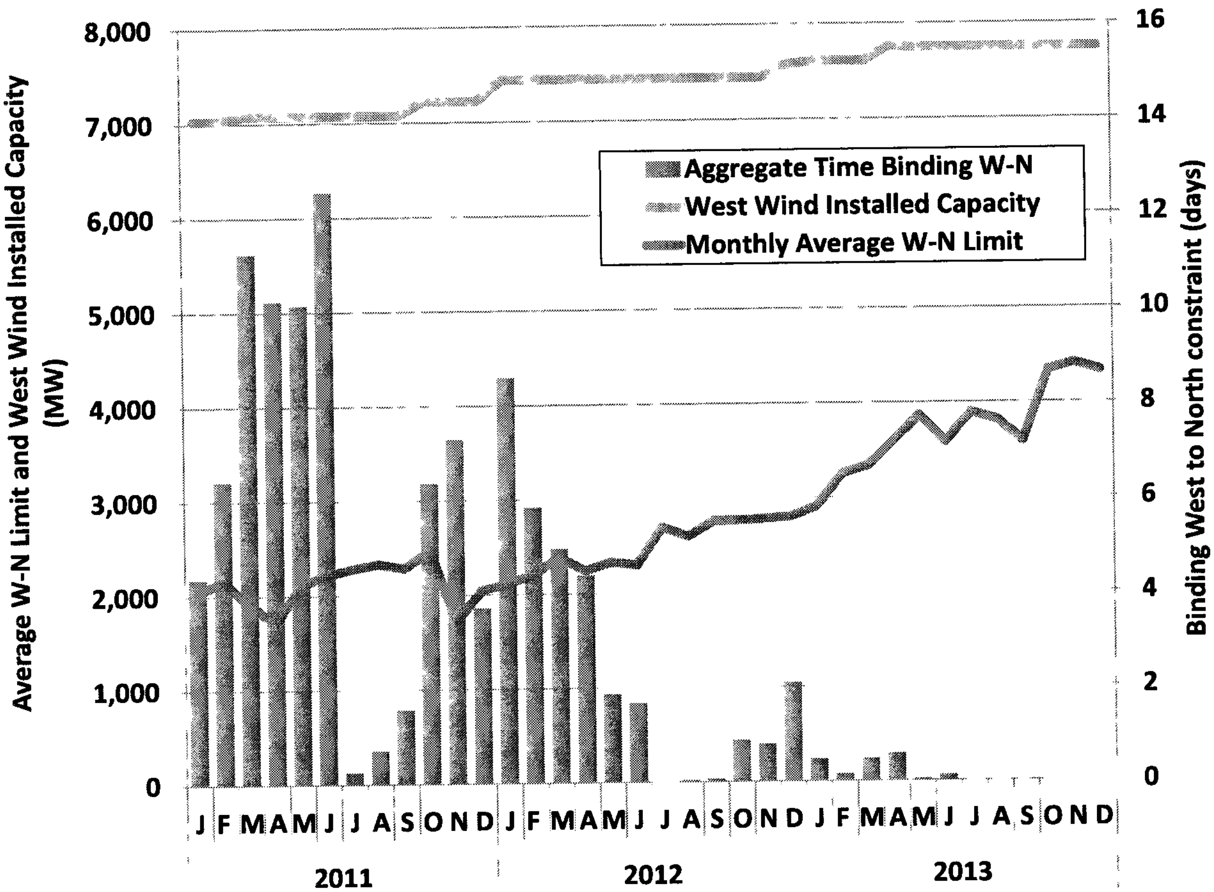



The Hamilton to Maverick 138 kV line, Paul 138/69 kV transformer, Aspermont area, and Alvin to Freeway Park 138 kV line are congested areas that did not have significant congestion costs. Hamilton to Maverick 138 kV line is a constraint in areas with limited transmission and also flows to an area in proximity to the Eagle Ford shale. The Paul 138/69 kV transformer, Aspermont area, and Alvin to Freeway Park 138 kV line are constraints that occurred due to outages in close proximity.

To maximize the economic use of scarce transmission capacity, the ideal outcome would be for the actual transmission line flows to reach, but to not exceed the physical limits required to maintain reliable operations. Prior to 2013, the West to North transmission constraint was perennially a top 10 real-time constraint. However, with the completion of the CREZ transmission lines at the end of 2013, the West to North constraint is no longer a significant factor. Figure 39 below presents a summary of the number of 24-hour periods that the West to

North interface transmission constraint was binding each month from 2011 through 2013. Even with continued increases in wind resources in the West zone, binding constraints affecting exports from the West zone fell sharply as the completion of CREZ lines resulted in higher limits on the West to North constraint.

**Figure 39: Utilization of the West to North Interface Constraint**




## C. Day-Ahead Constraints

In this subsection we review transmission constraints from the day-ahead market. To the extent the model of the transmission system used for the day-ahead market matches the real-time transmission system, and assuming market participants transact in the DAM similarly to how they transact in real-time, we would expect to see the same transmission constraints appear in the day-ahead market as actually occurred during real-time.

**Figure 40: Top Ten Day-Ahead Congested Areas**

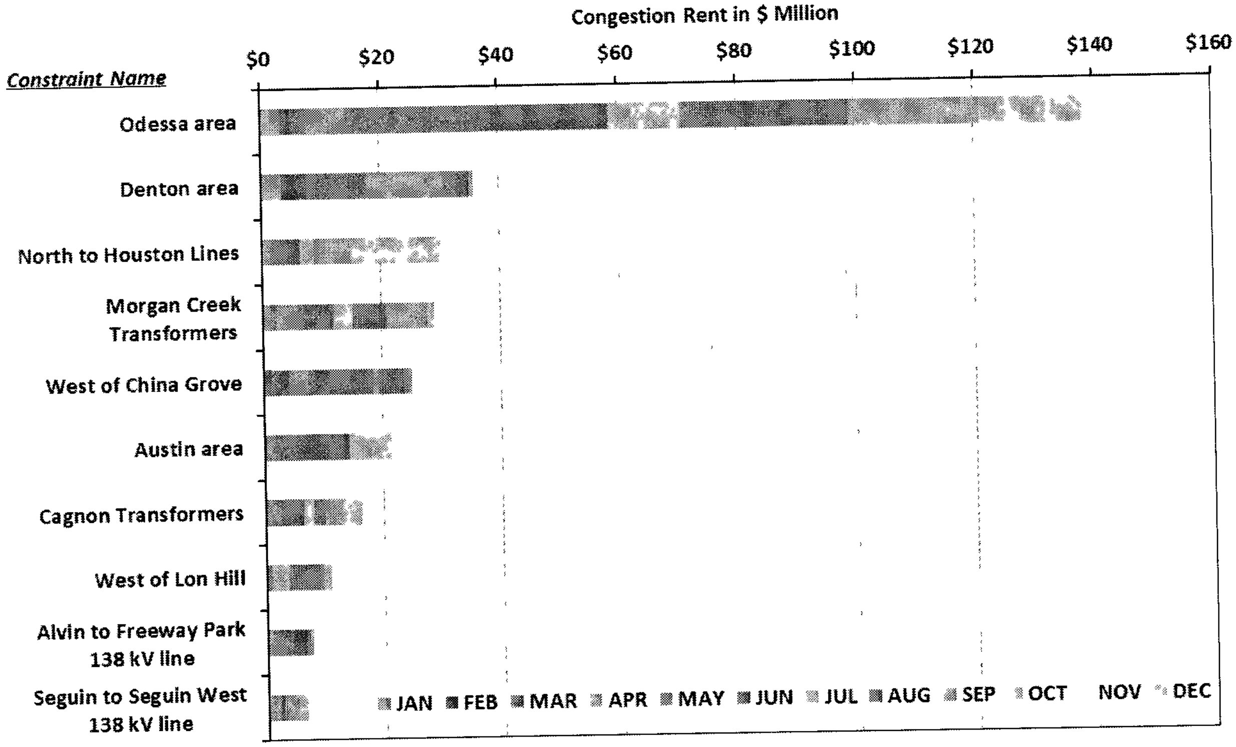
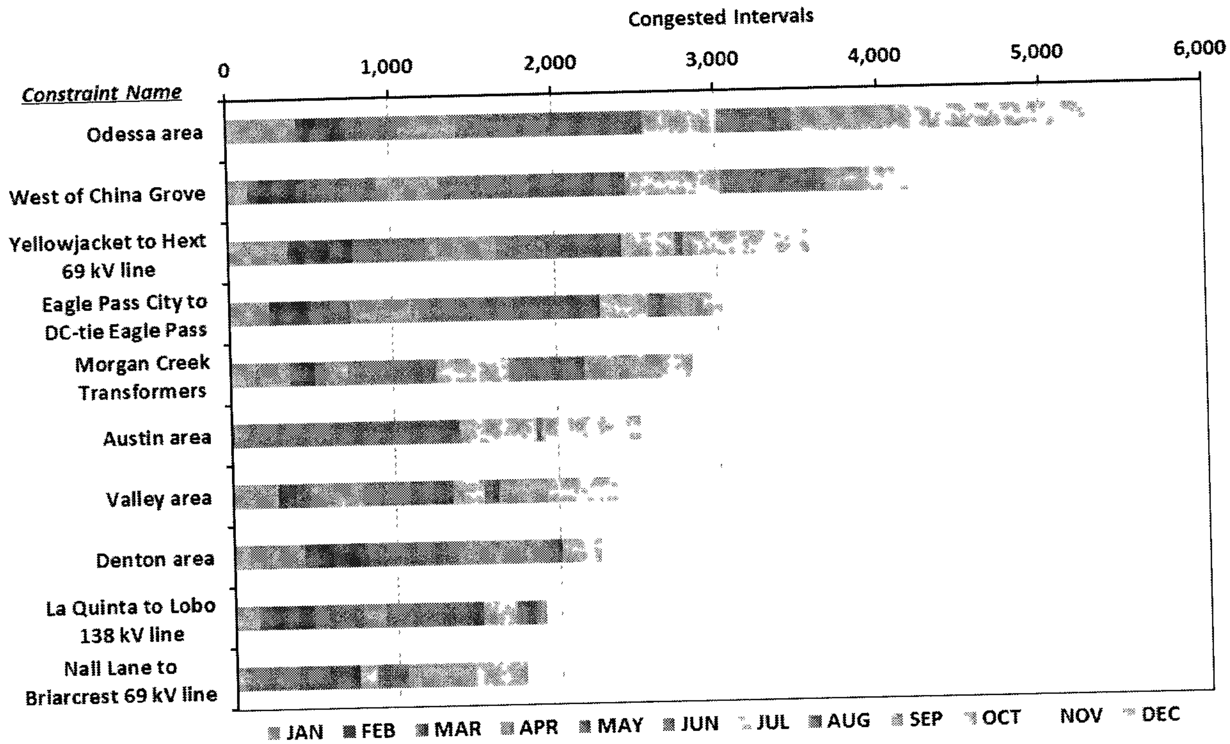



Figure 40 presents the top ten congested areas from the day-ahead market, ranked by their financial impact as measured by congestion rent. As was the case with the real-time constraints, day-ahead constraints in the Odessa area had the most significant financial impact. Only the Seguin to Seguin West 138 kV line constraint, which is related to serving load in the San Antonio area, was not included in the real-time list of constraints.

In our final analysis of this subsection we review the most frequently occurring day-ahead constraints shown in Figure 41.

**Figure 41: Most Frequent Day-Ahead Congested Areas**

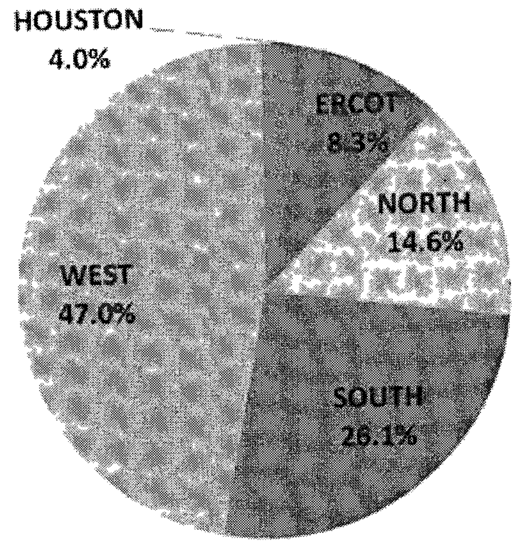



Two of the constraints appearing on the list would not occur in real-time. The Eagle Pass City to Eagle Pass DC Tie constraint appears frequently as a day-ahead constraint, but in real-time operations all transactions with Mexico using this DC Tie are scheduled using a separate process. The process would strictly limit the volume of transactions and not allow a constraint to occur. The Yellowjacket to Hext constraint is affected by a nearby phase shifter that depending on the tap setting of the element will have different impedances through the phase shifter. In the day-ahead market, the phase shifters are set at one value throughout the day, typically a mid-setting of the full range. The constraint seen in the day-ahead would likely not bind in real-time due to the fact that the tap settings can be changed to alter the flow over the elements.

With the exception of the La Quinta to Lobo 138 kV line, the remaining constraints listed in Figure 41 are related to limitations in the ability to transfer electricity to various load serving areas. The La Quinta to Lobo 138 kV line is located in a sparse transmission area of South Texas and related to the increased activity in the Eagle Ford Shale.

To further emphasize the effects of West and South zone congestion in 2013, Figure 42 highlights that, like real-time, day-ahead West and South zone congestion accounted for more than half the congestion in 2013. The amount of real-time congestion associated with facilities located in the West zone was more than 40 percent of the total congestion costs in 2013. This is a decrease from 2012 when more than 53 percent of real-time congestion costs were from the West zone.

**Figure 42: Day-Ahead Congestion Costs**



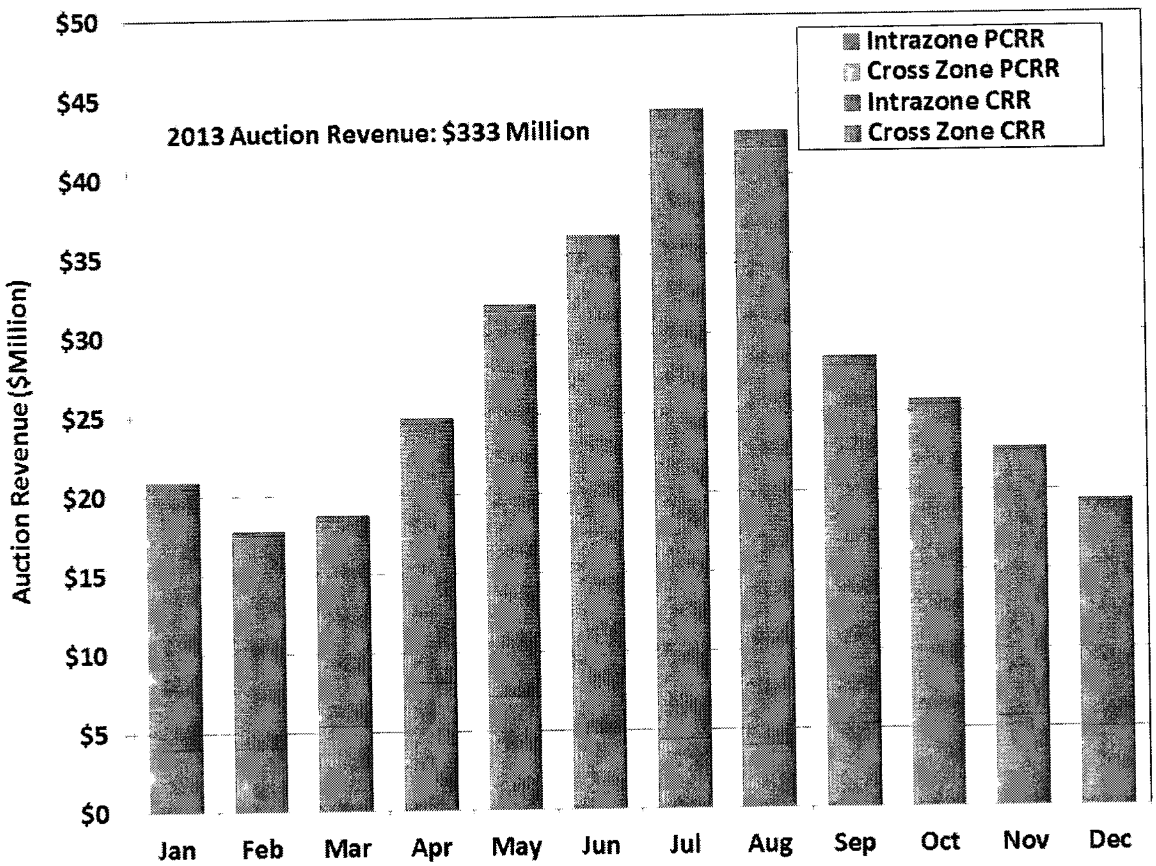

## D. Congestion Rights Market

Congestion can be significant from an economic perspective, compelling the dispatch of higher-cost resources because power produced by lower-cost resources cannot be delivered due to transmission constraint(s). Under the nodal market design, one means by which ERCOT market participants can hedge these price differences is by acquiring Congestion Revenue Rights ("CRRs") between any two settlement points.

CRRs are acquired by annual and monthly auctions while Pre-assigned Congestion Revenue Rights ("PCRRs") are allocated to certain participants based on their historical patterns of transmission usage. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same source and sink. Both CRRs and PCRRs entitle the holder to payments corresponding to the difference in locational prices of the source and sink.

Figure 43 summarizes the revenues collected by ERCOT in each month for all CRRs, both auctioned and allocated. These revenues are distributed to loads in one of two ways. Revenues from cross zone CRRs are allocated to loads ERCOT wide. Revenues from CRRs that have their source and sink in the same geographic zone are allocated to loads within that zone. This method of revenue allocation provides a disproportionate share of CRR auction revenues to loads located in the West zone. In 2013, CRRs with both their source and sink in the West zone accounted for 45 percent of CRR Auction revenues. This revenue was allocated to West zone loads, which accounted for only 8 percent of the ERCOT total. In comparison, in 2012, 27 percent of CRR Auction revenues were allocated to the West zone load, which accounted for 7 percent of the ERCOT total. Allocating CRR Auction revenues in this manner helps reduce the impact of the higher congestion on West zone prices.

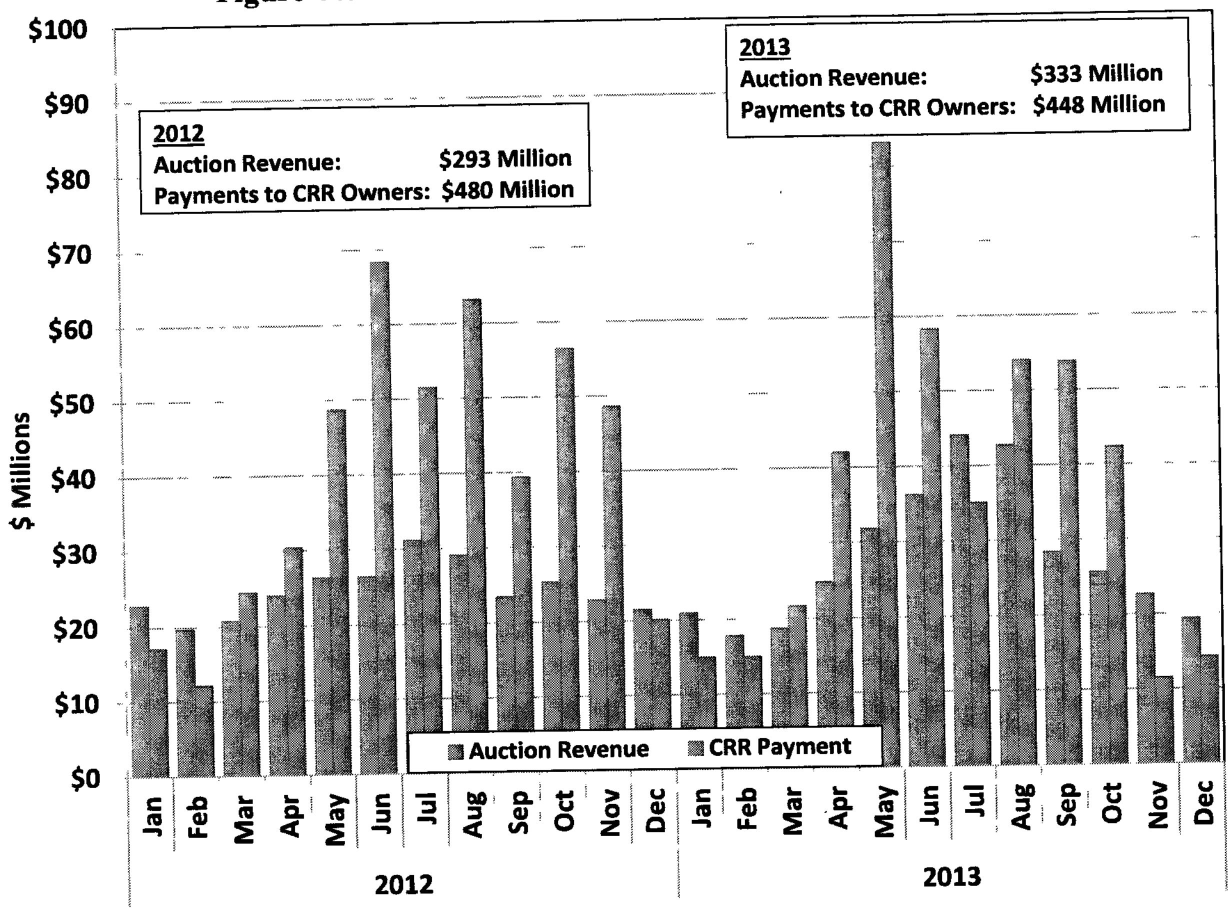
**Figure 43: CRR Auction Revenue**




As we showed in Section I.A, Real-Time Market Prices, the annual average price for the West zone was $37.99 per MWh, nearly $4 per MWh higher than the ERCOT-wide average. The value of CRR Auction revenues distributed only to the West zone equated to more than $5.50 per MWh higher than the amounts distributed to other zones. This was sufficient to offset the higher real-time prices incurred in the West load zone during 2013. In 2012 the annual average price for the West zone was $38.24 per MWh, which was about $10 per MWh higher than the ERCOT-wide average, and the incremental CRR Auction revenues were almost $3 per MWh.

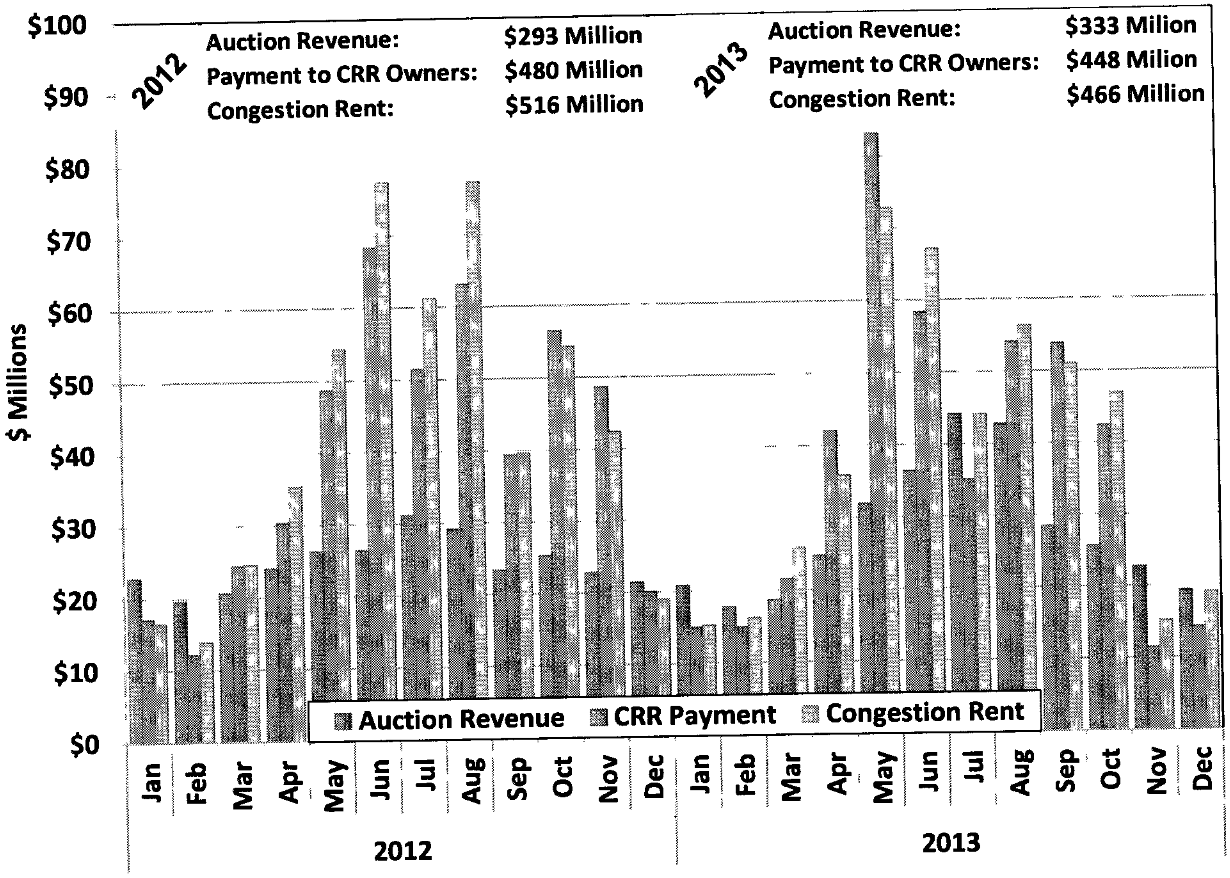
Next, in Figure 44 we examine the value CRR owners (in aggregate) received compared to the price they paid to acquire the CRRs. Although results for individual participants and specific source/sink combinations varied, we find that in most months participants did not over pay in the auction. Across the entire year of 2013, participants spent $333 million to procure CRRs and received $448 million.

**Figure 44: CRR Auction Revenue and Payment Received**




In our next look at aggregated CRR positions, we add congestion rent to the picture. Simply put, congestion rent is the difference between the total costs that loads pay and the total revenue that generators receive. Congestion rent creates the source of funds used to make payments to CRR owners. Figure 45 presents all three values for each month of 2012 and 2013. Congestion rent for the year 2013 totaled $466 million and payments to CRR owners were $448 million.

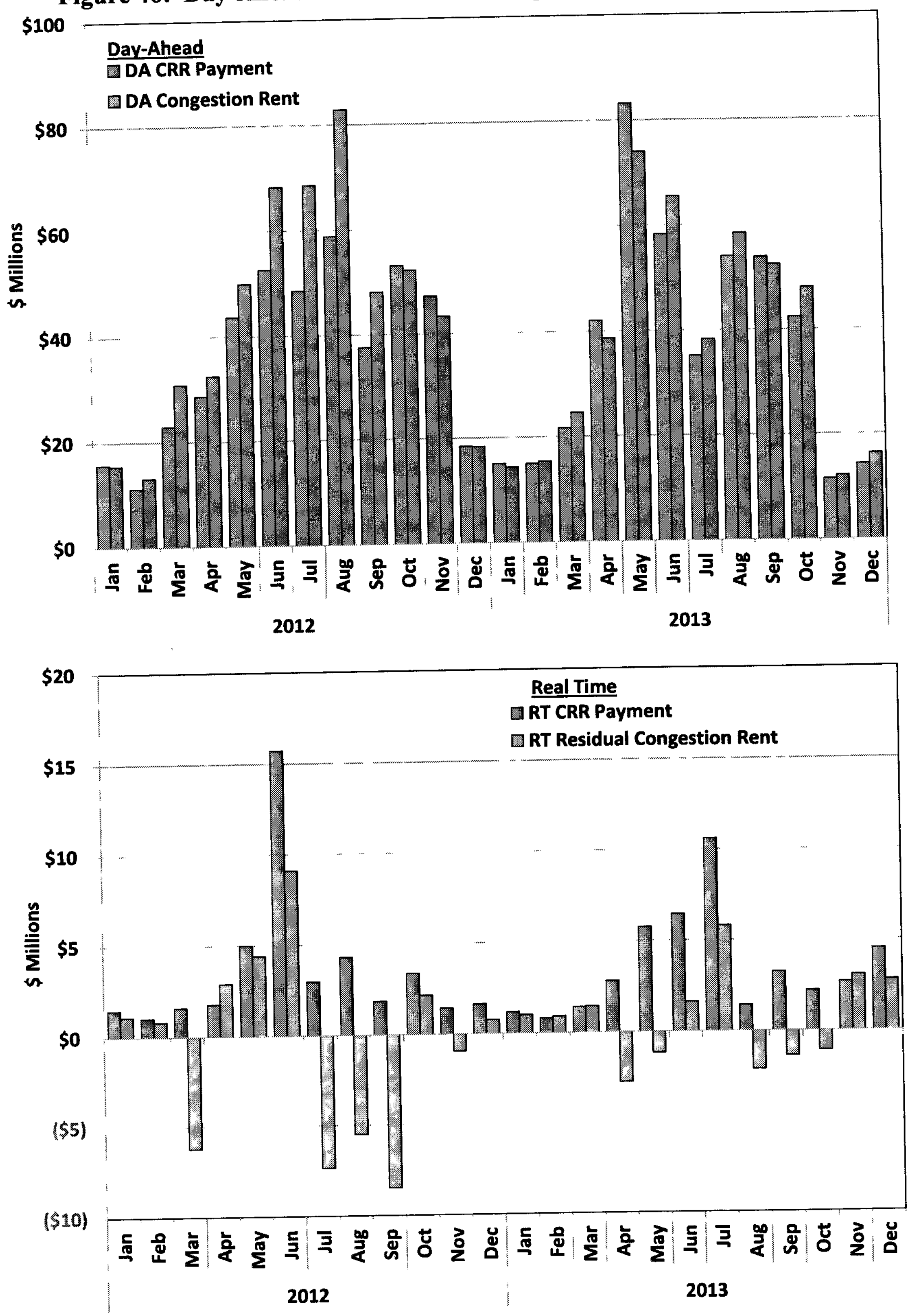
**Figure 45: CRR Auction Revenue, Payments and Congestion Rent**




We further analyze the relationship between congestion rent and payments to CRR owners by separating the impacts of CRRs that are settled based on day-ahead prices from the subset of CRRs that are paid based on real-time prices.

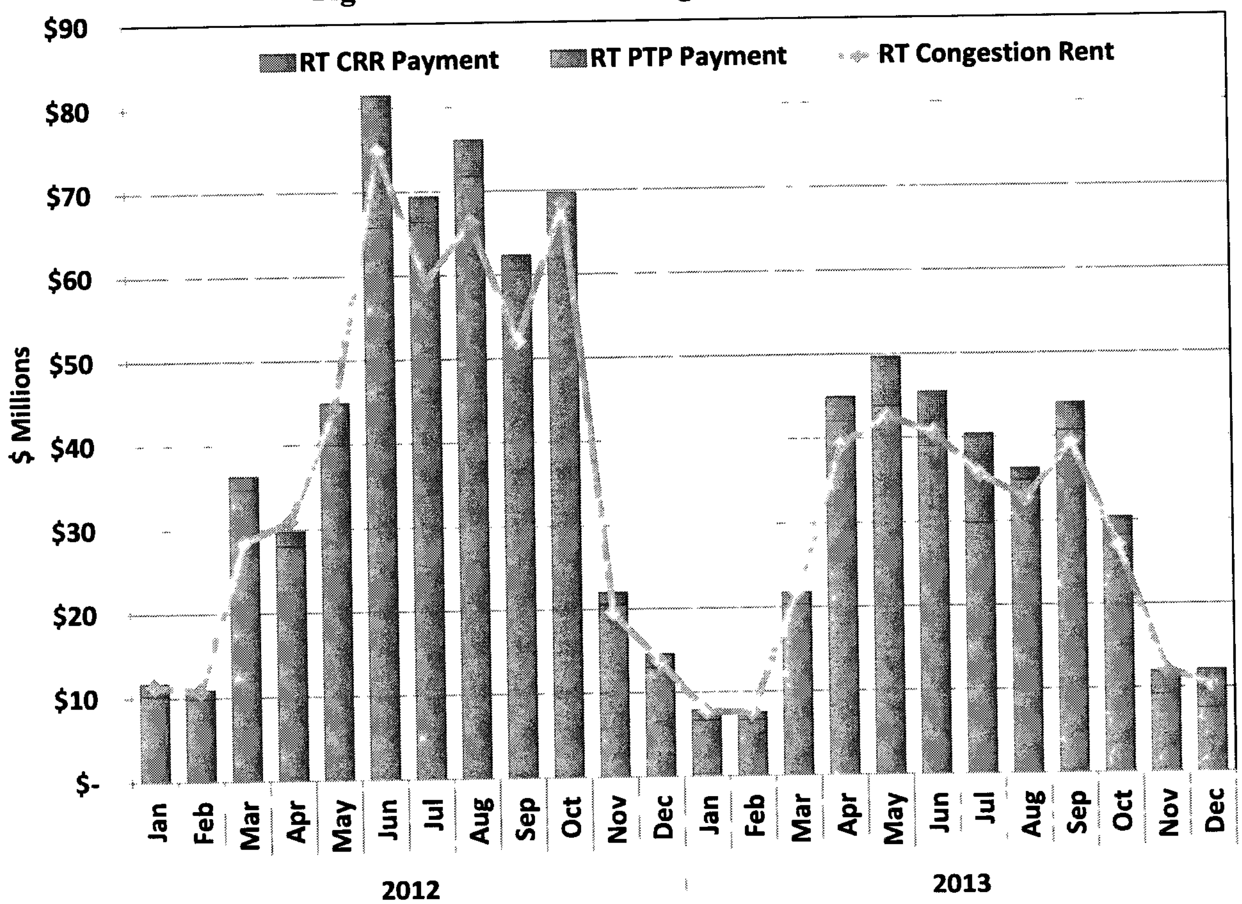
The top portion of Figure 46, shown below, displays the comparison of day-ahead congestion rent to payments received by CRR owners. Congestion rent was larger than payments in most months of 2013 and for the year congestion rent was $458 million compared to $446 million that was paid to CRR owners.

**Figure 46: Day-Ahead and Real-Time Congestion Payments and Rent**



The bottom portion of Figure 46 presents a different view. For this analysis we have assumed that all PTP Obligations have been fully funded from real-time congestion rent and any residual real-time congestion rent is available to fund payments to the subset of CRR owners that elected to have their CRRs be settled based on real-time prices. In 2013 there was more real-time congestion rent than the payments to holders of PTP Obligations, resulting in a $8 million surplus. However, there were real-time CRR payments of $43 Million. Hence, real-time congestion rent was insufficient to fund all PTP Obligations and CRRs being settled in real-time in the amount of $35 million. The next figure shows this explicitly.

**Figure 47: Real-Time Congestion Payments**



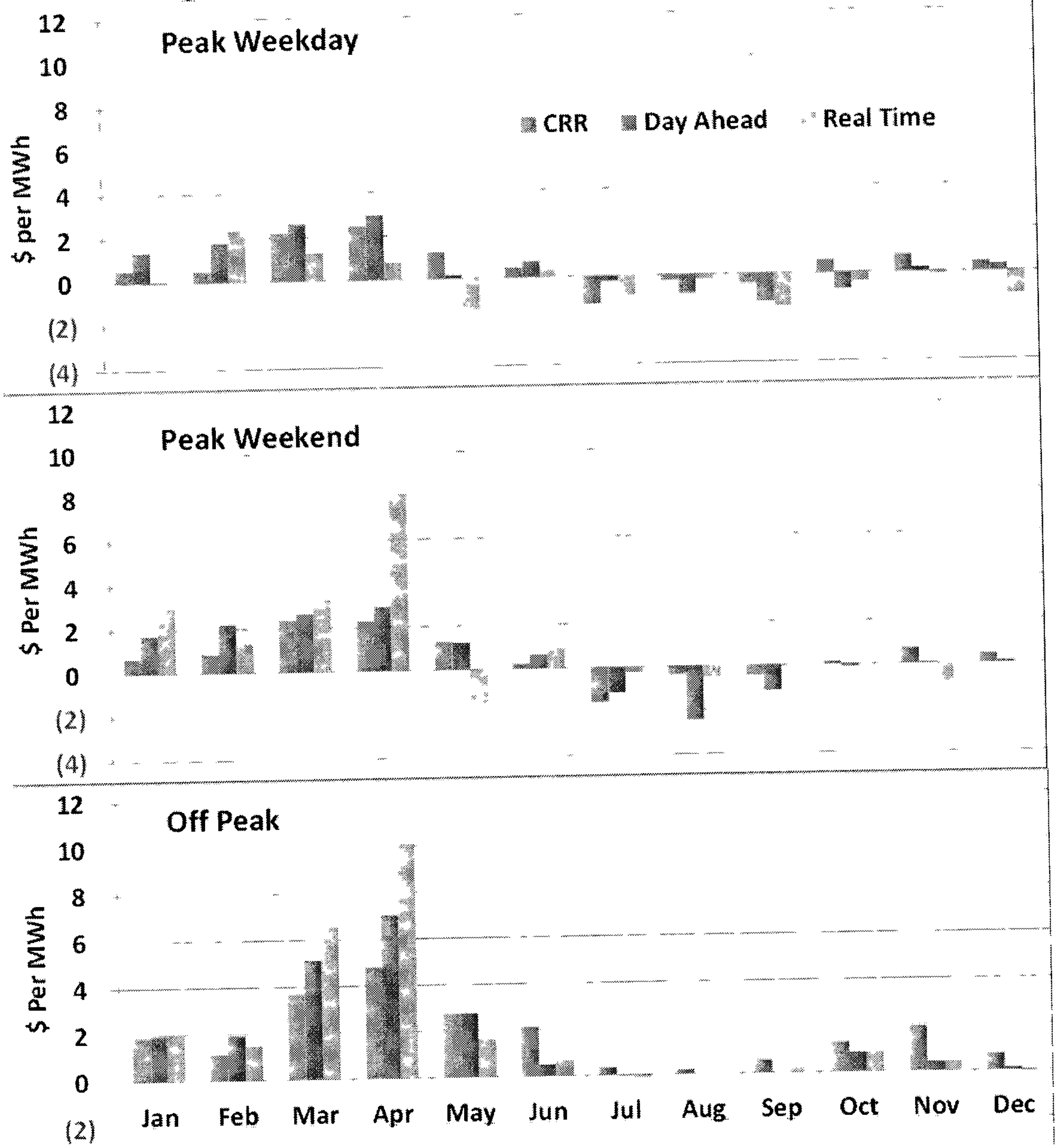

In Figure 47 the combined payments to PTP Obligation owners and CRR owners that have elected to receive real-time payments are compared to the total real-time congestion rent. For the year of 2013, real-time congestion rent was $317 million, payments for PTP Obligations were $309 million and payments for real-time CRRs were $43 million, resulting in a shortfall of approximately $35 million for the year. For the year of 2012, real-time congestion rent was

$480 million, payments for PTP Obligations were $487 million and payments for real-time CRRs were $42 million, resulting in a shortfall of approximately $49 million for the year. This type of shortfall typically results from discrepancies between transmission topology assumptions used when clearing the day-ahead market and the actual transmission topology that exists during real-time. Specifically, if the day-ahead topology assumptions allow too many real-time congestion instruments (PTP Obligations and CRRs settled at real-time prices) with impacts on a certain path, and that path constrains at a lower limit in real-time, there will be insufficient rent generated to pay all of the congestion instruments.

From Figure 47 we can see that April through October were the months with the most noticeable deficiencies. A detailed examination of the daily congestion pattern revealed no systemic concerns with the level of insufficiency. Deficiencies were generally small and attributed to many different constraints located in many different areas of ERCOT.

For our last look at congestion we examine the impacts of the West to North constraint in more detail. Figure 48 presents the price spreads between the West Hub and North load zone as valued at three separate points in time – at the monthly CRR auction, day-ahead and in real-time.

**Figure 48: West Hub to North Load Zone Price Spreads**




Since CRRs are sold for one of three defined time periods, weekday on peak, weekend on peak, and off peak, Figure 48 includes a separate comparison for each.

As expected, most real-time congestion, as evidenced by the largest price spread, occurred in the off peak period, for the months of March and April. The day-ahead price spreads were very similar for this period, while the prices paid for CRRs in March and April were more than the value received. Conversely, during the summer months of July and August, there was very little West to North congestion.

# IV. LOAD AND GENERATION

This section reviews and analyzes the load patterns during 2013 and the existing generating capacity available to satisfy the load and operating reserve requirements. We provide specific analysis of the large quantity of installed wind generation and conclude this section with a discussion of the daily generation commitment characteristics.

## A. ERCOT Loads in 2013

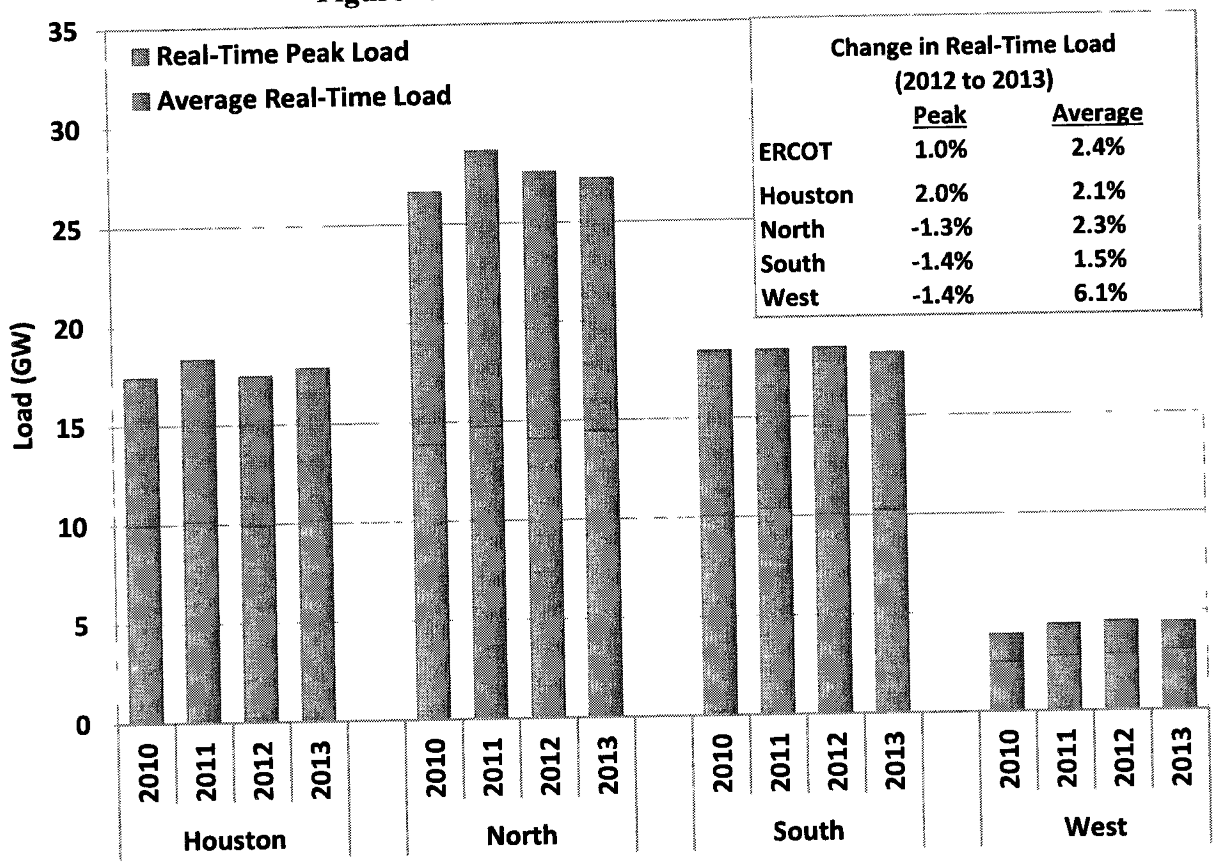
The changes in overall load levels from year to year can be shown by tracking the changes in average load levels. This metric will tend to capture changes in load over a large portion of the hours during the year. It is also important to separately evaluate the changes in the load during the highest-demand hours of the year. Significant changes in peak demand levels play a major role in assessing the need for new resources. They also affect the probability and frequency of shortage conditions (i.e., conditions where firm load is served but minimum operating reserves are not maintained). The expectation of resource adequacy is based on the value of electric service to customers and the harm and inconvenience to customers that can result from interruptions to that service. Hence, both of these dimensions of load during 2013 are examined in this subsection and summarized in Figure 49.

This figure shows peak load and average load in each of the ERCOT zones from 2010 to 2013.[8] In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 38 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (8 percent of the total ERCOT load).

Figure 49 also shows the annual non-coincident peak load for each zone. This is the highest load that occurred in a particular zone for one hour during the year; however, the peak can occur in different hours for different zones. As a result, the sum of the non-coincident peaks for the zones is greater than the annual ERCOT peak load.

8 For purposes of this analysis NOIE Load Zones have been included with the proximate geographic Load Zone.

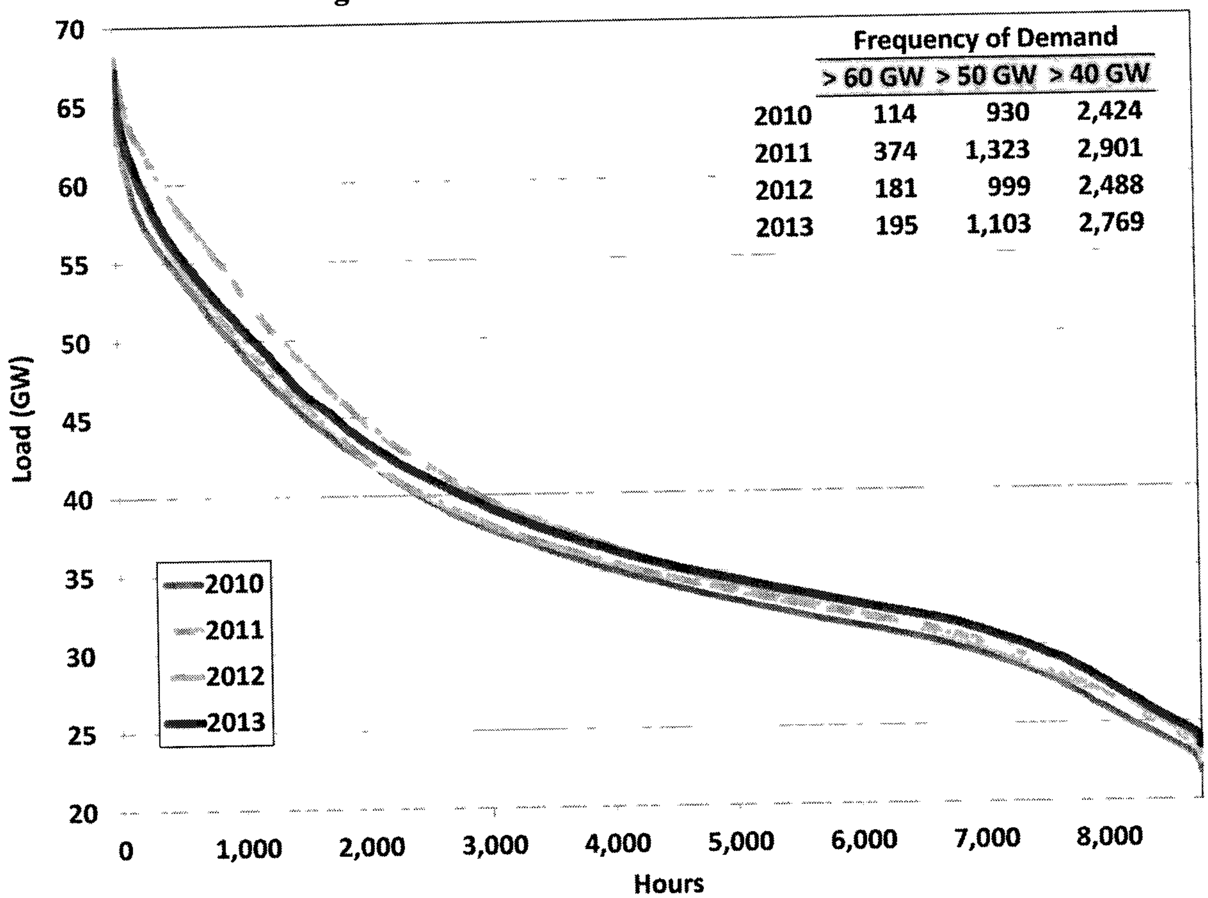
Figure 49: Annual Load Statistics by Zone




Total ERCOT load increased from 325 TWh in 2012 to 332 TWh in 2013, an increase of 2.1 percent or an average of 870 MW every hour. Similarly, the ERCOT coincident peak hourly demand increased from 66,559 MW to 67,245 MW in 2013, an increase of 686 MW, or 1.0 percent. The changes in load at the zonal level are not the same. Peak load in the Houston zone increased, while it decreased in the other zones. The average growth rate of load in the West zone once again was much higher, on a percentage basis, than the other zones.

To provide a more detailed analysis of load at the hourly level, Figure 50 compares load duration curves for each year from 2010 to 2013. A load duration curve shows the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT has a fairly smooth load duration curve, typical of most electricity markets, with low to moderate electricity demand in most hours, and peak demand usually occurring during the late afternoon and early evening hours of days with exceptionally high temperatures.

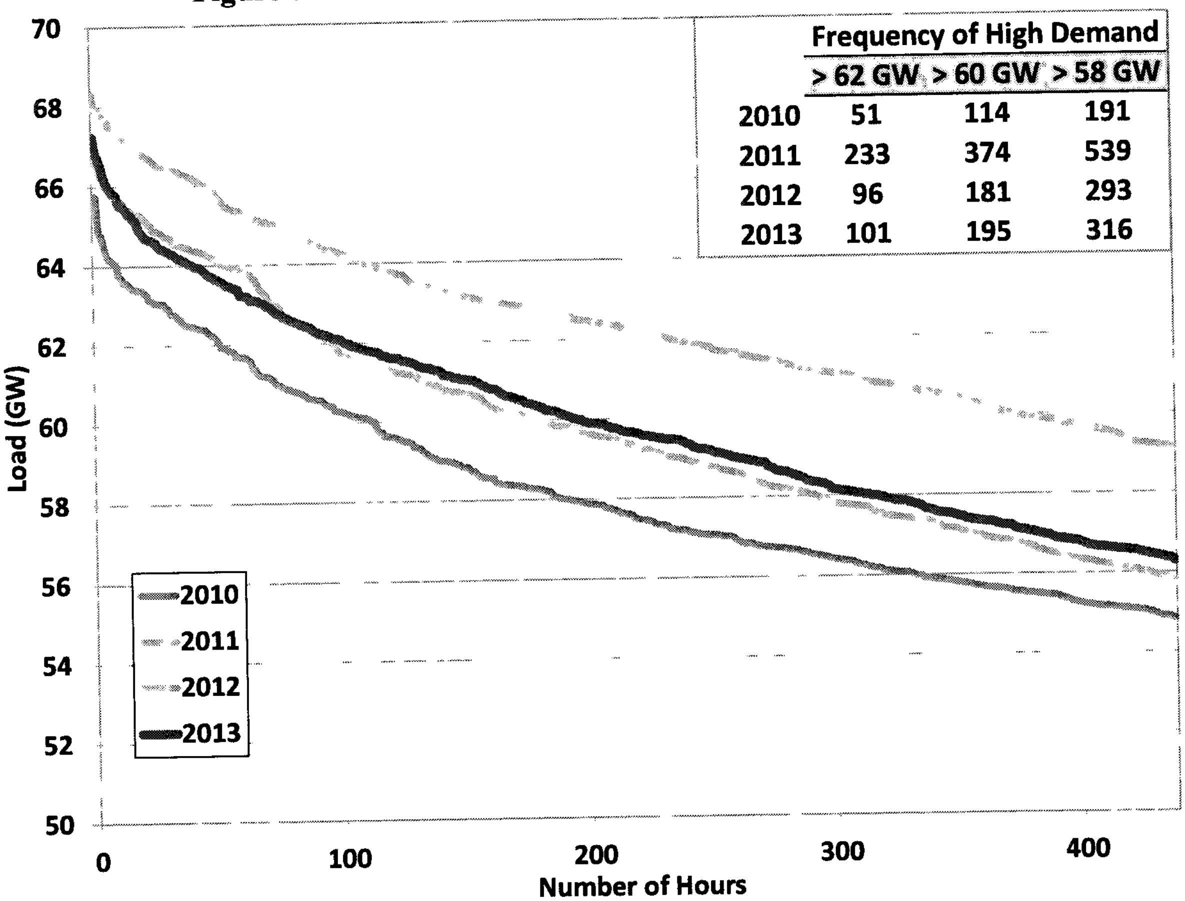
**Figure 50: Load Duration Curve – All hours**




As shown in Figure 50, the load duration curve for 2013 is slightly higher than in 2012 for most of the hours in the year. This is consistent with the aforementioned 2.1 percent load increase from 2012 to 2013.

To better illustrate the differences in the highest-demand periods between years, Figure 51 shows the load duration curve for the 5 percent of hours with the highest loads. This figure also shows that the peak load in each year is significantly greater than the load at the 95$^{th}$ percentile of hourly load. From 2010 to 2013, the peak load value averaged nearly 19 percent greater than the load at the 95$^{th}$ percentile. These load characteristics imply that a substantial amount of capacity – more than 10 GW – is needed to supply energy in less than 5 percent of the hours.

**Figure 51: Load Duration Curve – Top five percent of hours**

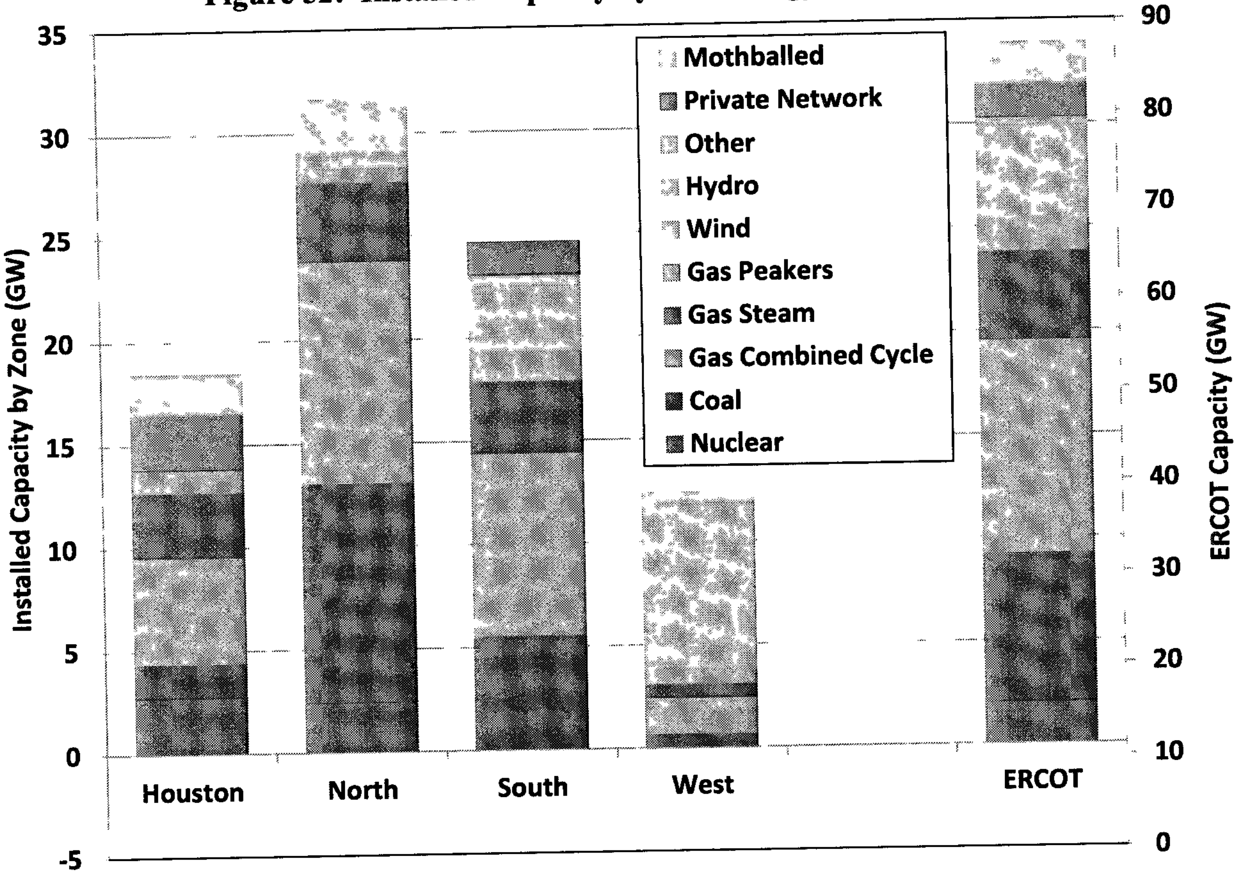



## B. Generation Capacity in ERCOT

In this subsection we evaluate the generation mix in ERCOT. The distribution of capacity among the ERCOT zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West zone. The North zone accounts for approximately 36 percent of capacity, the South zone 28 percent, the Houston zone 21 percent, and the West zone 14 percent. The Houston zone typically imports power, while the West zone typically exports power. Excluding mothballed resources and including only 8.7 percent of wind capacity as capacity available to reliably meet peak demand, the North zone accounts for approximately 40 percent of capacity, the South zone 30 percent, the Houston zone 23 percent, and the West zone 6 percent. Figure 52 shows the installed generating capacity by type in each of the ERCOT zones.[9]

[9] For purposes of this analysis, generation located in a NOIE Load Zone has been included with the proximate geographic Load Zone

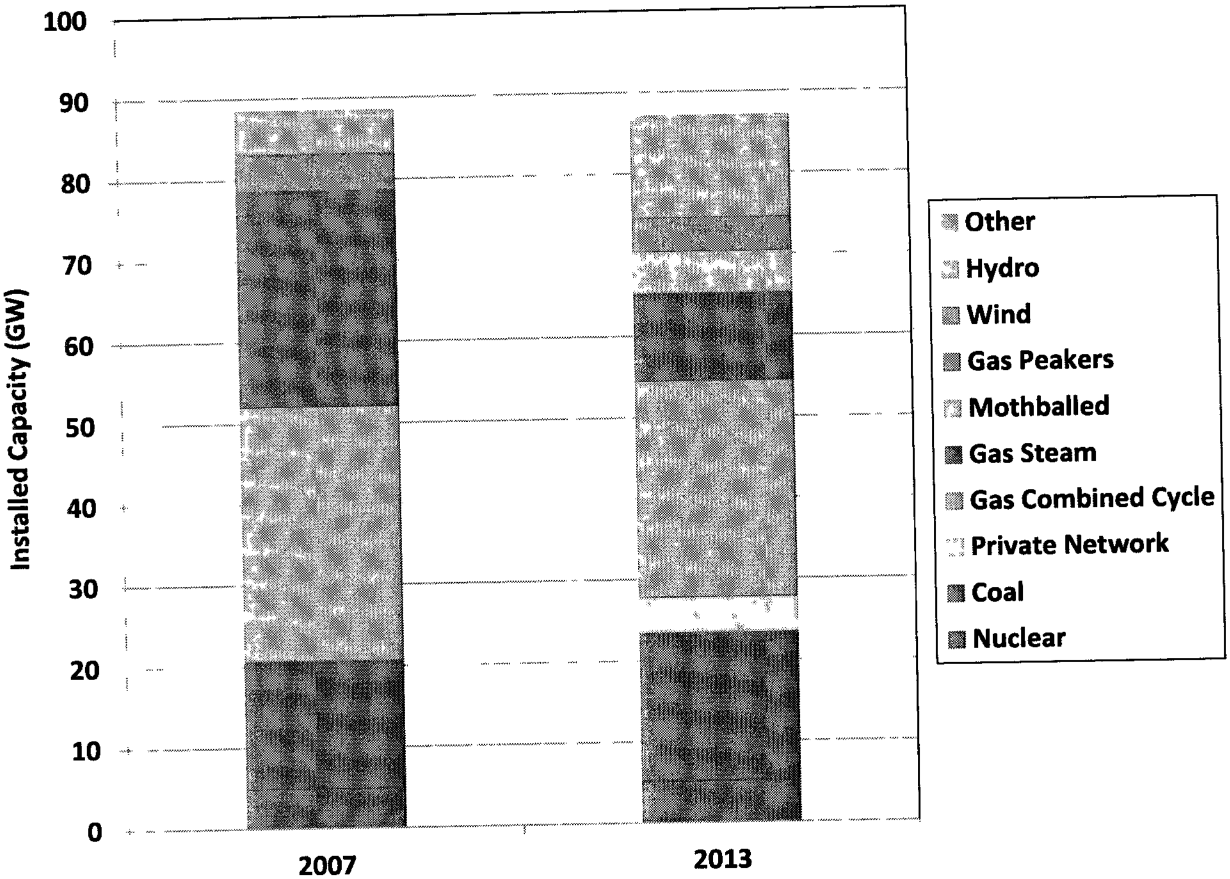
Figure 52: Installed Capacity by Technology for each Zone




Approximately 1.6 GW of new generation resources came online in 2013, the bulk of which was a large (970 MW) coal unit. The other additions were wind, gas and solar units. When unit retirements are included, the net capacity addition in 2013 was 1 GW. After the capacity changes in 2013 the mix between natural gas and coal generation remains stable. Natural gas generation accounts for approximately 48 percent of total ERCOT installed capacity and coal for approximately 21 percent.

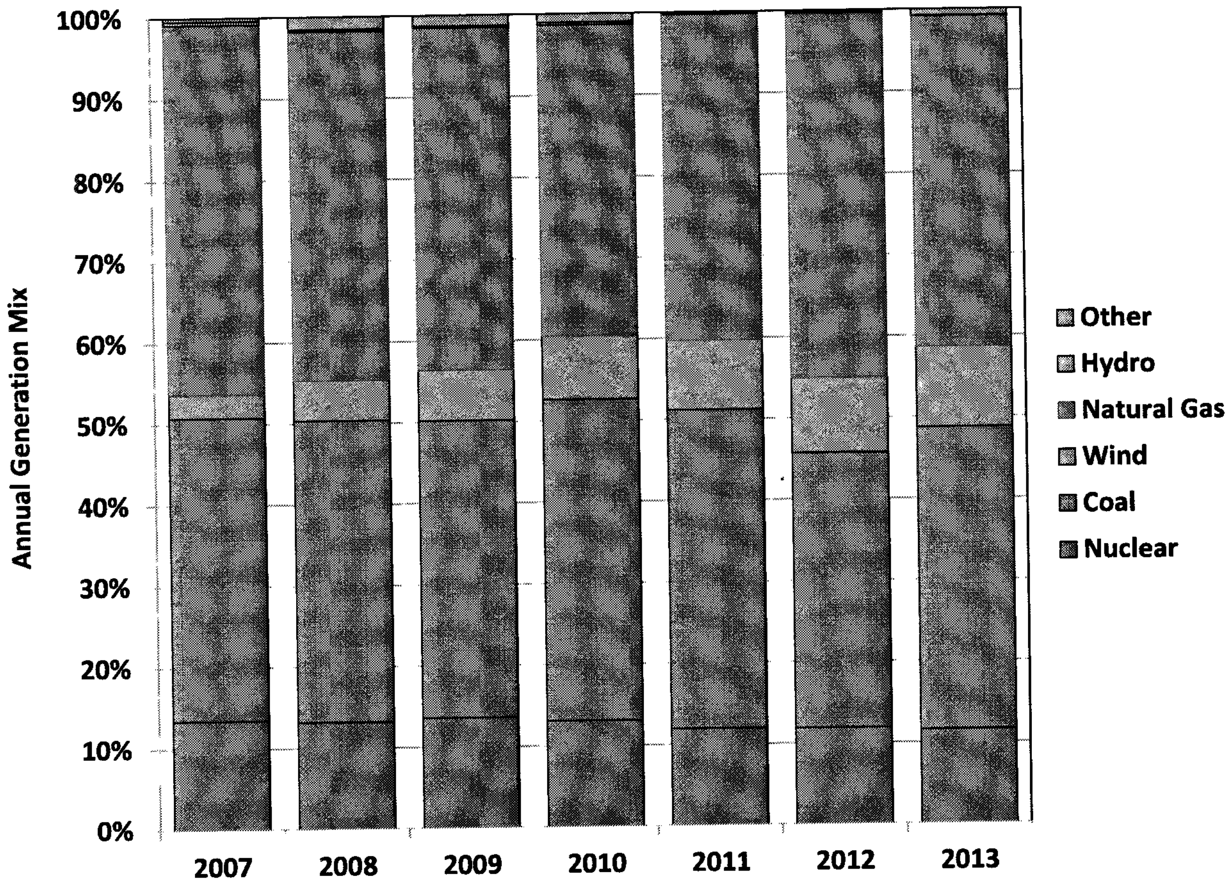
By comparing the current mix of installed generation capacity to that in 2007, as shown in Figure 53, we can see the effects of longer term trends. Over these seven years, wind and coal generation are the two categories with the most increased capacity. The sizable additions in these two categories have been more than offset by retirements of natural gas-fired steam units, resulting in less installed capacity in 2013 than there was in 2007.

**Figure 53: Installed Capacity by Type: 2007 to 2013**




The shifting contribution of coal and wind generation is evident in Figure 54, which shows the percentage of annual generation from each fuel type for the years 2007 through 2013. The generation share from wind has increased every year, reaching 10 percent of the annual generation requirement in 2013, up from 3 percent in 2007. During the same period the percentage of generation provided by natural gas has ranged from a high of 45 percent in 2007 to a low of 38 percent in 2010. In 2013 the percentage of generation from natural gas decreased slightly from 2012 to 41 percent. Correspondingly, the percentage of generation produced by coal units ranged from a high of 40 percent in 2010 to a low of 34 percent in 2012. The percentage of generation from coal increased to 37 percent in 2013. The rebound in the share of generation produced by coal in 2013 was due to the increase in natural gas prices from the historical low levels experienced in 2012.

**Figure 54: Annual Generation Mix**




While coal/lignite and nuclear plants operate primarily as base load units in ERCOT, it is the reliance on natural gas resources that drives the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23.5 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price. However, due to the low price of natural gas in 2012, we observed that the share of generation produced from coal-fired and nuclear units decreased to less than half of the energy in ERCOT, with the reduction coming from decreased coal generation. This reduction in the share of coal generation resulted in an increase in the occurrences when coal units were setting the price. This happens because the decrease in natural gas price results in those units becoming infra-marginal; that is, less costly than the last unit needed to satisfy total demand. As natural gas units are marginal less frequently, coal units increasingly become marginal. We can see the results of this tradeoff in Figure 55 which shows that the frequency with which coal was the marginal fuel was greater than 40 percent in all